The Geothermal Potential of Low Enthalpy Deep Sedimentary Basins in the UK

HIRST, CATHERINE,MARY

The Geothermal Potential of Low Enthalpy Deep Sedimentary Basins in the UK

Catherine Mary Hirst

A thesis submitted in fulfilment of the requirements for the degree of Doctor of Philosophy at Durham University

Department of Earth Sciences

Durham University

2016

Abstract

Low enthalpy geothermal resources located within deep Permian and post-Permian sedimentary basins across the UK are estimated to contain at least 300 EJ ($x10^{18}$ J) of heat, sufficient if fully developed to supply all heating needs in the UK for the next century. The geothermal heat estimate is based on data held within the Geothermal Catalogue (Busby, 2010). A source of deep well data not included in the Geothermal Catalogue is held by the oil and gas industry; access to this data has allowed new geothermal research to be undertaken to re-evaluate and constrain an existing geothermal resource (the Cheshire Basin), and to evaluate a previously un-quantified resource (the East Midlands). These areas were determined based on the availability of oil and gas well data. Data relating to the East Midlands indicate the total available extractable heat from produced oil and co-produced water located in Carboniferous sediments totals 2.64 MW_t. In the Welton Field water from non-oil bearing horizons are factored in; the extractable heat increases from 0.91 MW_t to 1.6 MW_t. The Cheshire Basin uses the offshore East Irish Sea Basin as an analogue to better constrain the aquifer properties of the Triassic Sherwood Sandstone Group (SSG) and Permian Collyhurst Sandstone Group (CS). It also assesses the connectivity of these Groups across the basin. The Helsby Sandstone Formation (part of the SSG) will likely exhibit a minimum transmissivity of 4.26 D m alone. Data for the CS were inconclusive due to diverging porosity trends between the basins; transmissivity could be on average 0.13 D m or 3.85 D m with resulting flow rates of 47.7 m^3 d^{-1} or 1431 m^3 d^{-1}. Factoring in reservoir stimulation is deemed necessary if the CS is to be targeted. The connectivity of the basin is restricted by large N-S orientated largely cemented faults, restricting flow in an E-W orientation. In addition the connectivity is further affected by facies heterogeneity and diagenesis; this increases tortuosity that may be advantageous in a geothermal context.

The work is pertinent given the UK's commitment to the Kyoto Protocol and Renewable Energy Directive. Geothermal technologies are low CO_2 emitters, are non-intermittent, unobtrusive, do not attract large emission-based taxes, have long (~25 year) lifespans and have minimal post-use clean-up costs. The uptake of geothermal resource within the UK still remains low, however, indicating barriers to uptake exist. Technical barriers (i.e. those relating to drilling of the well, geology, flow rates and temperature) are not limiting uptake. Non-technical barriers relating to lack of risk insurance schemes and longer payback times owing to the relative value of hot water versus petroleum are identified as restricting factors to the uptake of geothermal resources.

Geothermal energy development in the UK is still in its infancy and work such as this only strengthens the case for investment. The potential for geothermal resource exploitation to offset the conventional energy consumed to produce heat is sizeable; no other renewable technology has the capacity to deliver heat that low enthalpy geothermal offers.

List of Figures

List of Tables

List of Equations

DECLARATION

The work contained within this thesis has not been submitted for a degree at any other institution. The work herein is solely that of the author. Any exceptions have been duly cited and referenced where necessary.

Catherine Mary Hirst
Department of Earth Sciences
Durham University
September 2016

Acknowledgements

When I began this PhD back in 2012 I didn't really know what I was getting myself into. It's been more challenging than I could ever have imagined but I wouldn't go back and change a thing. The opportunities that I've had and the people I have met along the way are what have made this process one of the most fulfilling I've done. There are lots of people I need to thank who helped me along the way, the most important being my supervisors here at Durham University: Prof. Jon Gluyas and Dr. Simon Mathias. Jon you have been a constant source of inspiration throughout having provided me with the necessary knowledge and tools to complete this project. I hope you realise that after most of our meetings I had to have an hour or so digesting what we'd discussed (in a good way, I hasten to add)! Simon, whilst I know maths is not my forte you have nonetheless always persevered with me providing me with plenty to think about – new angles I'd not thought of and new ways to approach my data. And I did use Matlab, even if it was just to plot graphs so all is not lost.

Thanks go to my industry supervisor at BP, Dr. Santo Bains. I know BP have a continually changing energy portfolio but you've always supported this work and I'm very grateful for you agreeing to fund this project, and for your input. Last of all I'd like to thank my final supervisor, Prof. Paul Younger who played a large role in getting this project off the ground. It was your supervision during my MSc that set me on this path and for that I am thankful.

I'd like to thank Kelsey Ward and IGas Energy PLC who provided a large amount of data for me to work on. In a similar fashion I'd also like to thank Richard Wardle, Neil Brister, Jonathan Craig and ENI Ltd for also providing me with a large volume of data. Without your help this project would be more like a pamphlet!

Thanks go to Dr. Charlotte Adams – thanks for being an unofficial supervisor! Being able to talk through my work with you has been invaluable and I am very grateful as a result.

I'd like to thank the CDT group, Douglas Halliday and Katie Daniels for the additional funding, support and opportunities that I've had the chance to take part in throughout my time here. In addition thanks go to CeREES.

Thanks go to the many PhD's/postdocs/staff that have been here whilst I have studied. In particular Peace, Bob, and DCI Brodie – we've all gone through the mill at a very similar time but I've always appreciated the chat and support (and bike rides/bike chat/bike everything). Pete – thanks for being a desk-mate for several years (even if you did frequently blame me for your bodily noises rather loudly across the open plan). Katie, Sarah, Stephan, Ben, Anna, Dean, Fran, Alison, Andy, Sian, Jordan, Kate, Tom U, Fienke, Eddie, Matt, Janice, Paula – the list goes on! Thanks go to all. Thanks also go to the Ustinov Unicorn girls for the last few years of laughs both on and off the pitch. It's appreciated!

Rob and Michael – cheers for the bike-riding thesis breaks, the climbing trips, the support when I kept injuring myself, the countless cakes, teas and coffees, the support when we go off and do ridiculous bike races – the list goes on. Although really you should be grateful I talk to you at all since I am Cat Hirst off of Strava…

Mum, Dad, James, Liz, Dan and Toby (and bump/now known as baby Isobel!) – thanks for being, well, family! Always there, always listening even if you hadn't got a clue what I was wittering on about. Special thanks go to mum and dad for the roof, the countless dinners, the many lifts and generally putting up with all my stuff (literally – at least I have a storage container for most of it now).

Finally thank you to Sam. Thank you for listening to my endless chatter about geothermal and bikes, for helping me to stay positive when the end never felt like it would come, for cheering me up with your autocorrected messages, and for the many times you've had to look after me due to various bike-related accidents. Even though I told you the wrong hospital you still came to my rescue! Anyway, you've always been there when I needed you, and for that I can't say thank you enough.

List of Abbreviations

ADEME	French Environment and Energy Management Agency
AFPG	Association Française des Professionnels de la Géothermie
AFTA	Apatite Fission Track Analysis
AGEA	Australian Geothermal Energy Association
AGRCC	Australian Geothermal Reporting Code Committee
AONB	Area of Outstanding Natural Beauty (UK)
BGL	Below Ground Level
BGR	Federal Institute for Geosciences and Natural Resources
BGS	British Geological Survey
BHT	Bottom Hole Temperature
BMU	Federal Ministry for the Environment, Nature, Conservation and Nuclear Safety
BSL	Below Sea Level
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CISB	Central Irish Sea Basin
COP21	United Nations Framework Convention on Climate Change
DECC	Department of Energy and Climate Change, UK
DFG	Danish Geothermal District Heating
DST	Drill Stem Test
EEG	Renewable Energy Sources Act 2012
EEWärmeG	Renewable Energies Heat Act 2009
EGEC	European Geothermal Energy Council
EGS	Engineered Geothermal System
EISB	East Irish Sea Basin
FIT	Feed-In-Tariff
GEA	Geothermal Energy Association
GEODH	Geothermal District Heating
GEOELEC	Geothermal Electricity
GEUS	Geological Survey of Denmark and Greenland
GIC	Groundwater Investigation Consent
GSHP	Ground Source Heat Pump
HDR	Hot Dry Rock
HNDU	Heat Networks Delivery Unit
IGA	International Geothermal Association
IPCC	Intergovernmental Panel on Climate Change
KH	Horizontal Permeability
KV	Vertical Permeability
LCOE	Levelised Cost of Energy
LGM	Last Glacial Maximum
LIAG	Liebniz-Institut für Angewandte Geophysik
LWD	Logging While Drilling
MD	Measured Depth
MWD	Measurement While Drilling

NEGB	Northeast German Basin
NGB	North German Basin
NREAP	National Renewable Energy Action Plan
NWGB	Northwest German Basin
OPEC	Organisation of the Petroleum Exporting Countries
ORC	Organic Rankine Cycle
Platform Geothermie	Geothermal Platform
Poroperm	Porosity-permeability
R&D	Research & Development
REA	Renewable Energy Association
REN	Renewable Energy Directive
RHI	Renewable Heat Incentive
ROC	Renewable Obligation Certificate
SDE+	Stimulation Sustainable Energy Plus
SEI Aardwarmt	Guarantee Scheme
SSG	Sherwood Sandstone Group
SSSI	Site of Special Scientific Interest (UK)
TVDSS	True Vertical Depth (SubSea)
VR	Vitrinite Reflectance

Units

°C	Centigrade
°C km^{-1}	Temperature Gradient per km
BBL	Barrel
cP	Centipoise
mD	Milli-Darcy
D	Darcy
D m	Darcy metres
kg m^{-1} s^{-1}	Dynamic Viscosity
kg s^{-1}	Mass flow rate
kJ kg^{-1} K	Specific Heat Capacity
kWh m^{-2}	Energy per unit area / Heat Density
m d^{-1}	Hydraulic Conductivity
Mg m^{-3}	Density
mW m^{-2}	Heat Flow
MW_e / GW_e	MW electric / GW electric (Power)
MW_t / GW_t	MW thermal / GW thermal (Power)
MWh / GWh	Megawatt Hours / Gigawatt Hours (Energy)
Pa	Pascal
psi	Pound per Square Inch
SG	Specific Gravity
SCFS	Standard Cubic Feet
W m^{-1} K^{-1}	Thermal Conductivity
EJ	Exajoules 10^{18} (Energy)

PJ	Petajoules 10^{15} (Energy)
TJ	Terajoule 10^{12} (Energy)

Conversion Factors

Refer to Table 6.12 for complete conversions of transmissivity, intrinsic permeability and hydraulic conductivity

Metric	Imperial / non-SI
1 m^3 d^{-1}	0.01157 L s^{-1}
1 m^3 d^{-1}	6.289811 bbl d^{-1}
1 m^3	35.3146667 scfs
1.000 SG	10°API
0.998 Mg m^{-3}	10°API
1 Pa	0.000145038 psi
1 m	3.28 ft
1 kg m^{-1} s^{-1}	1000 cP

10000 m^2	1 Ha

Degrees API	API = (141.5 / SG) -131.5 SG = Specific Gravity at 60°F

Degrees Fahrenheit	°C x (9/5) + 32

Darcy-milliDarcy-Intrinsic Permeability-Hydraulic Conductivity	1 D = 1000 mD = 9.87E-13 m^2 = 0.74 m d^{-1}

Chapter 1:

Introduction

1.1 Project Overview & Rationale

Energy consumption across the world reached a peak of 104,000,000 GWh as of end 2012 (International Energy Agency, 2015). A total of 84.1% of this energy was provided by fossil fuels (oil, natural gas, coal, electricity), a resource that will eventually reduce in size and will ultimately produce an energy gap. In addition to this concerns relating to human-driven climate change have forced the world to re-assess the expulsion of fossil fuel derived greenhouse gases into the Earth's atmosphere. To address these issues the Kyoto Protocol (United Nations, 1997) was introduced and signed by over 180 countries committed to halting rising greenhouse gas emissions. The agreement, reviewed periodically, stated emissions be "reduced by 12.5% below 1990 emissions by 2008-2012, and by 80% below 1990 emissions by 2050". The Kyoto Protocol commitment goes hand-in-hand with increasing the uptake of renewable low carbon technologies to cover the energy shortfall created by reduced fossil fuel dependence. The most recent development in the tackling of climate change has been the 21st Conference of Parties to the United Nations Framework Convention on Climate Change (COP21), held in Paris between 30 November 2015 and 11th December 2015. Here the primary concern of the 195 state parties was to agree on how to limit global temperature increase to a maximum of 2°C above pre-industrial levels. At the time of writing, 187 out of 195 members have agreed to emission-reducing commitments beginning in 2020. These are to be reviewed on a 5 year basis. The Paris Agreement will come into force once 55 parties have accepted the terms.

Geothermal technologies fit the remit of being a low carbon, clean, green, sustainable technology (Younger et al., 2012) that could help reduce dependence on fossil fuels and contribute towards reducing CO_2 emissions. The potential of this technology has been recognised by oil companies including BP and Chevron (the latter being the current largest producer of geothermal energy), and as such efforts have been made to research and characterise these resources. Geothermal research by the hydrocarbon industry is partly driven by a need to diversify their energy portfolio, but also pressure from Government and society has also had a hand in forcing the issue.

As of 2015, the total installed capacity of geothermal power plants across the world amounted to 12,635 MW_e, whilst produced energy was 73,549 GWh (Bertani, 2015). With regards direct utilization of geothermal resources (i.e. heat only projects), a total of 70,329 MW_t was produced as of end-2014 (Lund and Boyd, 2015). Within the UK there are no geothermal projects that generate electricity although two Engineering Geothermal Systems (EGS)/Hot Dry Rock (HDR) projects have been granted planning approval, both located in Cornwall, Southwest England (Batchelor et al., 2015). That aside, the electricity generating capacity of the UK is limited by geological and tectonic setting. However, a lower temperature resource base does exist associated with deep sedimentary basins; low enthalpy resources. Low enthalpy resources are generally defined as being <100°C in temperature and are therefore exploited for heat only. Low temperature geothermal is currently only utilised on a large scale in Southampton, where one single well point has previously exploited water at 76°C from the Triassic Sherwood Sandstone aquifer (1729-1767 m depth), within the Wessex basin. The Sherwood Sandstone displays both lateral and vertical permeability that allows water to be pumped at a rate of 860 m^3 day^{-1} (Adams et al., 2010). The heat contained within this water has been used to both heat and chill retrofitted public/commercial buildings, 3000 homes and 10 schools within the centre of Southampton (Batchelor et al., 2015; Southampton City Council, 2009). The scheme produced a total of 30,000 MW_t of which 18% is produced solely by the geothermal well (the remainder being provided by fuel oil and natural gas CHP system). The well is currently undergoing an overhaul having been on production for over 20 years.

Aside from Southampton the UK resource base has been explored but not yet exploited. An assessment of the low enthalpy geothermal resource base has previously been undertaken and was last updated in 1995 (Rollin et al., 1995). Similar geothermal systems to that seen at Southampton have been identified in several places across the UK but they have yet to be exploited (Downing & Grey, 1986; Rollin et al., 1995). A major assessment of UK geothermal resources was undertaken between 1976 and 1986 that resulted in quantification of the low enthalpy geothermal resource held in Mesozoic basins, as well as an estimation of subsurface temperatures. It used existing borehole data made available from various industries / sources to make this assessment which was subsequently compiled into a catalogue; the Geothermal Catalogue. Whilst the catalogue has been actively updated, it uses only 3057 subsurface temperatures from 1216 sites, 567 of which are from wells >1 km depth from which to interpolate from (Busby, 2010). Based on borehole data collected during this study, the combined geothermal resource for Mesozoic basins (excluding the Larne basin) was estimated to be 300 EJ ($x10^{18}$ J). UK heat consumption currently totals approximately 3 EJ per annum, suggesting there is enough heat stored in these basins to decarbonise the UK heat requirement for the next 100 years (Younger et al., 2012).

Technological advances and new data availability since 1986 suggest a re-evaluation of onshore low enthalpy geothermal resources is now required. In addition to the geothermally viable locations identified in the original geothermal assessment, there is now scope to add to the database by tapping into the large volumes of existing oilfield data that were previously unavailable. Not only will these data aid the constraint of already identified resources, but also provides an opportunity to quantify the resource held in other areas of the UK. The technological advancement provides one reason for undertaking this study, but there are other reasons why a re-assessment is due, including the aforementioned climate change.

Control of renewable energy production and promotion within the EU is covered by the Renewable Energy Directive (Directive 2009/28/EC, 2009). The Directive states that by 2020, at least 20% of total EU energy needs are provided from renewable sources, and 10% of transport fuels must be derived from renewable sources. The Directive is further broken down into individual national targets which are weighted depending on a 2009 baseline of renewable energy production, as well as the general potential for producing renewables. The UK Department of Energy and Climate Change (DECC), as directed by the EU Renewable Energy Directive cited above, has designed and implemented the Renewables Obligation Order (DECC, 2014) to fulfil the UK's renewable obligations. The Renewables Obligation Order states that by 2020, 15% of the UK's final energy consumption must come from renewable energy resources (DECC, 2009). Geothermal can therefore play a role in achieving the targets set out above.

1.2 General Project Aims & Objectives

Section 1.2 deals with the more general aims and objectives of this project. Within individual chapters more refined aims and objectives can be found.

The primary aim of this project is to re-assess or newly quantify the low enthalpy geothermal resource located in selected onshore deep (>300 m) sedimentary basin settings using new previously unused deep well data supplied by the oil and gas industry. Secondary to this is the identification of barriers to the uptake of low enthalpy geothermal resources in the UK using data from other geological and tectonically similar countries to determine what likely inhibits further development.

Two selected areas have been identified to satisfy the primary aim; the East Midlands and the Cheshire Basin. Access to onshore and offshore well data held by the oil industry has been granted for these areas which expand the existing data set used in the estimate of sub-surface temperatures, flow rates, aquifer properties and stratigraphy. The Cheshire Basin has an analogous offshore oilfield (the East Irish Sea Basin) that has been used to better constrain the likely aquifer properties of the Cheshire Basin. In addition the structural control on fluid flow within the basin has also been assessed to provide comment on the connectivity/transmissivity and lateral continuity of productive strata within the basin. The East Midlands was identified as a location where the underlying oil-bearing Carboniferous strata could be quantified with regards the amount of extractable heat within both produced oil and co-produced hot water (something not previously attempted before). Assessment of the local heat demand and potential end-users of the available heat has also been assessed as part of this study.

Key objectives were defined as follows:

1. Identify the source of geothermal heat and the mechanism involved in how heat is transferred to the Earth's surface.
2. Determine how heat measurements are made and identify the issues with taking direct measurements.
3. Locate the key areas that are important for geothermal resources within the UK.
4. Identify and discuss the previous geothermal exploration that has taken place in the UK.
5. Identify the geothermal resources located in selected European countries, and compare the UK resource base to these other countries.

6. Identify the barriers encountered within these countries and determine the methods employed to overcome such barriers.
7. Identify data associated with the East Midlands Petroleum Province and extract temperature, flow rate and aquifer properties data for these fields.
8. Produce a quantification of extractable heat and therefore geothermal resource based on the extracted data.
9. Identify users of the produced heat.
10. Compare and contrast the offshore East Irish Sea Basin to the onshore Cheshire Basin to determine if offshore data can be used to compliment onshore data.
11. Identify barriers to the movement of fluid across the basin using offshore and onshore data.
12. Quantify the transmissivity likely present in the identified target aquifers and compare with previous estimates.

Hypothesis: There are additional geothermal resources that have previously not been quantified that will add to the already known geothermal resource base within the UK. A secondary hypothesis is that data from the oil and gas industry are appropriate for constraining UK geothermal resources.

1.3 Chapter Summaries

An overview of each Chapter is presented below. Where a Chapter has already been published in an academic journal, the co-author list is presented and a note on the level of my input is highlighted.

Chapter 1: Introduction: An introduction to the project is provided within this Chapter. It states the rationale behind this project and the overall aims and objectives of the work.

Chapter 2: An overview of geothermal concepts: Provides a technical overview of heat distribution and geothermal resources on a global scale. The aim of Chapter 2 is to provide a foundation in understanding geothermal concepts. It initially explores the basic concepts of geothermally-derived heat, how that heat is transferred and distributed across the surface of the Earth and further identifies the mechanisms that disturb the geotherm at shallow depths. An overview of terminology, classification systems and definitions of geothermal resource/reserve are further discussed setting the precedent for the terminology that will be used within this thesis. Finally a background in UK geothermal resource development has been presented.

Chapter 3: Geothermal energy systems of the UK and neighbouring European Countries: A comparison of resources, their exploitation and barriers to their development: An overview of World geothermal resource status and the economic and political factors driving or hindering uptake of geothermal resource schemes is discussed within Chapter 3. The use of low enthalpy geothermal resources from selected countries is compared alongside the UK to identify the barriers and limitations of resource exploitation. These barriers have been described as technical (i.e. as a result of variations in geology) and non-technical (i.e. as a result of Government policy and legislation). The cause of the UK's limited geothermal resource uptake is discussed.

Chapter 4: The late field life of the East Midlands Petroleum Province – A new geothermal prospect?: The East Midlands forms the study area for two chapters within this thesis. The resource quantified within these Chapters has not been assessed prior to this time, and as such provides new data for the geothermal resource estimate of the UK. In addition it forms a unique resource with surface infrastructure already in place, and the reservoirs are already well understood thus reducing the cost of geothermal resource development. Chapter 4 deals with a single oilfield (the Welton field) where data has been extracted and used to produce an estimate of stored heat. Flow rate data are freely available from the Department of Energy and Climate Change (DECC) but this does not take into account other potential water-only strata within these fields. The resource quantification takes these additional strata into account when estimating the volume of available fluid in the field. End-users for this heat have subsequently been identified to determine the most economically viable use of the heat.

Chapter 5: The geothermal potential held within Carboniferous sediments of the East Midlands: A new estimation based on oilfield data: Chapter 5 partially builds on Chapter 4 and provides a broad scale estimate of extractable heat within 23 oilfields located in the East Midlands based on historic oil and water flow rates and a corrected temperature gradient used to estimate temperatures at target depths. Chapter 5 also presents a comparison of a more general-scale assessment of resource with the more targeted resource valuation presented in Chapter 4 indicating this larger scale resource assessment is conservative.

Both Chapter 4 and Chapter 5 have been published, the former within the Quarterly Journal of Engineering Geology and Hydrogeology, the latter in the 2015 World Geothermal Congress conference journal (Hirst and Gluyas, 2015; Hirst et al., 2015b). Both works are co-authored. In both Chapters my co-authors input was in an advisory capacity, and 100% of the written element and science was undertaken solely by myself. The paper that forms Chapter 4 has since been awarded the Professor William R Dearman QJEGH Young Author of the Year 2015 award. Both papers can be found in Appendix A and B respectively.

Chapter 6: The Cheshire Basin – using an offshore analogue to better constrain onshore geothermal aquifer parameters: The Cheshire Basin study area was selected as further offshore analogue data for the neighbouring East Irish Sea Basin was made available by ENI Ltd. These data compliment the sparse dataset already utilised in previous geothermal resource estimates for the Cheshire Basin. The Chapter is a development of a co-authored paper published in the 2015 World Geothermal Congress conference journal (Hirst et al., 2015a), found in Appendix C. As lead author I completed 80% of the science and written element of this paper, with input from co-authors being partially advisory (10%) and partially as a written element (10%).

The initial part of Chapter 6 determined if use of an offshore analogue (the East Irish Sea Basin) was appropriate by comparing and contrasting basin development by assessing the depositional environment and sedimentation histories, the structural development, burial and maturation histories and diagenesis. From these data it was determined the basins were comparable and data from each could be used to aid geothermal resource quantification.

Drawing on the information gained in the initial basin comparison the Chapter further explores the limitations of previous resource quantification. By using both published and offshore data, lateral continuity of reservoir and non-reservoir sections offshore has been used to estimate the likely effect on permeability and porosity distribution. Structural data (flow barrier versus conduit) were viewed alongside the observed diagenetic effects accumulated throughout the burial and subsequent exhumation across the Cheshire Basin. Information regarding aquifer properties within the East Irish Sea Basin was used to compliment the sparse dataset from the Cheshire Basin to place constraints on likely transmissivity that could be obtained from the deeper parts of the basin. It highlights the importance of using analogue data to aid our understanding of onshore areas that contain very few deep data.

Chapter 7: Discussion and Conclusions: Chapter 7 brings together all the elements of the work undertaken to form a general discussion on the geothermal resource base of the UK. The work is placed in a wider context to determine how successful the resource quantification has been and whether the primary and secondary hypothesis has been proven.

1.4 References

Adams, C. A., Gluyas, J. G., and Mathias, S. A., 2010, Application of hydrogeological parameters for evaluating the thermal resource potential of deep groundwater systems, BHS Third International Conference : Role of hydrology in managing consequences of a changing global environment.: Newcastle upon Tyne, British Hydrological Society.

Batchelor, T., Curtis, R., Ledingham, P., and Law, R., 2015, Country Update for the United Kingdom: Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Bertani, R., 2015, Geothermal Power Generation in the World 2010-2014 Update Report, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Busby, J., 2010, Geothermal Prospects in the United Kingdom, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.

DECC, 2009, National Renewable Energy Action Plan for the UK: Article 4 of the Renewable Energy Directive 2009/28/EC: Department of Energy and Climate Change (DECC).

-, 2014, Renewables Obligation Order 2009: Department of Energy and Climate Change (DECC).

Directive 2009/28/EC, 2009, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

Hirst, C. M., and Gluyas, J. G., 2015, The Geothermal Potential Held within Carboniferous Sediments of the East Midlands: A New Estimation Based on Oilfield Data, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Hirst, C. M., Gluyas, J. G., Adams, C. A., Mathias, S. A., Bains, S., and Styles, P., 2015a, UK Low Enthalpy Geothermal Resources: the Cheshire Basin, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Hirst, C. M., Gluyas, J. G., and Mathias, S. A., 2015b, The late field life of the East Midlands Petroleum Province; a new geothermal prospect?: Quarterly Journal of Engineering Geology and Hydrogeology, v. 48, no. 2, p. 104-114.

International Energy Agency, 2015, Key World Energy Statistics.

Lund, J. W., and Boyd, T. L., 2015, Direct Utilization of Geothermal Energy 2015 Worldwide Review, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Rollin, K. E., Kirby, G. A., Rowley, W. J., and Buckley, D. K., 1995, Atlas of Geothermal Resources in Europe: UK Revision: British Geological Survey, Regional Geophysics Series, Technical Report WK/95/07.

Southampton City Council, 2009, Geothermal and CHP Scheme - Southampton City Council.

United Nations, 1997, Kyoto Protocol to the United Nations Framework Convention on Climate Change.

Younger, P. L., Gluyas, J. G., and Stephens, W. E., 2012, Development of deep geothermal energy resources in the UK: Proceedings of the Institution of Civil Engineers - Energy, v. 165, no. 1, p. 19-32.

Chapter 2:

An Overview of Geothermal Concepts

2.1 An Overview of Geothermal Concepts

To understand geothermal energy it is important to understand how heat is produced, how it moves and how it is distributed across the surface of the Earth. The following section will discuss the theme of heat and place it in context with geothermal energy.

2.1.1 Heat Flow

Understanding the thermal budget of the Earth is important when assessing the thermal dynamics of the planet. The evolution, movement and surface expression of the produced heat are observed around the globe. An understanding of the changing nature of heat production through Earth history can be derived through various means that include the following (Huenges, 2010).

- Studying the chemical composition of chondrites.
- Combined seismic studies and mineral physics studies.
- Pressure-temperature-time reconstructions derived from mineral assemblages within eroded orogens.

The process of generating heat and transferring it throughout the structure of the Earth is not a simple process, and it is not distributed equally. With regards the geothermal potential of a given location, we must first appreciate the larger scale heat-generating processes that occur prior to focusing on the small scale disturbances we see within the geothermal systems of interest.

Heat flow at the Earth’s surface will be discussed here, but will only quote data on internally produced heat. Solar heat flux provides a large amount of heat and is of importance on surface processes, but it only has an effect within 10-20 m of the Earth’s surface and as such is not considered further within Section 2.1.1.

2.1.1.1 Core Heat Generation and Distribution

The temperature within the core of the Earth has recently been reported as being ~6000°C (Anzellini et al., 2013), producing the majority of Earth’s heat that is then dissipated throughout the structure of the Earth. Heat flow can be measured across the surface of the Earth; world average surface heat flow is determined to be 86 mW m^{-2} (Davies, 2013). Within the UK, background heat flow is 52 mW m^{-2} (Busby, 2014). UK heat flow varies across the UK depending on the thickness and type of rock; southwest England has an elevated heat flow of 117 mW m^{-2} and average geothermal gradient of 35°C km^{-1} (elevated from a UK average of 26°C km^{-1}) due to the radiogenic granites underlying the area

(Busby, 2014). How heat is transferred and distributed across the mantle and ultimately to the crust is of importance in geothermal studies.

Heat is generated through several internal processes that can be classed as either primordial heat or radioactive heat. Primordial heat relates to the following processes:

- Secular cooling / accretionary energy: the energy involved during the formation of the Earth and subsequent gradual cooling of the produced kinetic energy.
- Adiabatic Energy: energy caused by compression during the growth of the Earth.
- Crystallisation of the inner core, in particular settling of Iron (Fe) crystals.

Radioactive decay of radio-isotopes (U, Th, K) also produces additional heat to the above processes. Primordial heat-producing processes were at their greatest during early Earth history and have since been slowly declining. Huenges (2010) after Jaupart et al. (2007), states there are total heat losses of 46 TW within the core and mantle of the Earth. Further work undertaken by Davies and Davies (2010), estimate Earth's surface heat flux to be 47 TW. Jaupart et al. (2007), c.f.Huenges (2010) indicate the following breakdown of total heat source/loss from within the Earth (Figure 2-1).

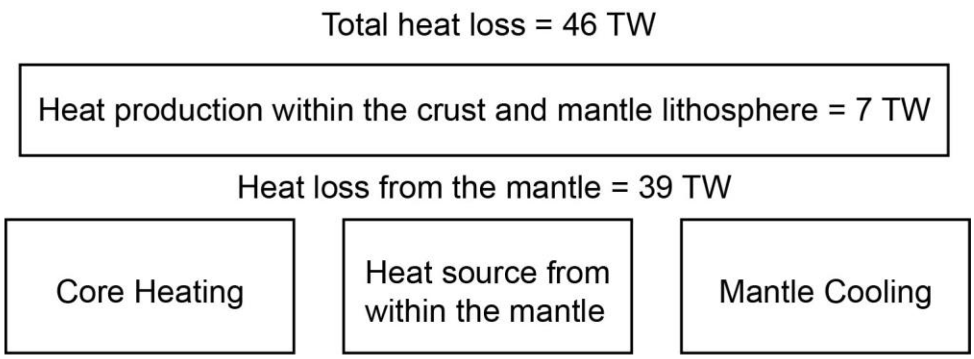


Figure 2-1: Heat sources and losses within the Earth (Huenges, 2010; Jaupart et al., 2007).

The generated heat is transferred through the Earth's mantle to the base of the lithosphere through conduction, convection and radiation processes. How such heat is then distributed between oceanic lithosphere and continental crust is important in attempting to forecast temperature gradients at any given point on the Earth's surface. Prediction of heat flow is based primarily on conduction of heat through rock. Fourier's Law describes this movement in much the same way Darcy's Law describes groundwater flow through rock. It is the product of the thermal conductivity and temperature gradient, both which can be measured directly or estimated and is described in Equation 2-1:

Equation 2-1: Fourier's Law

$$Q = -\lambda A \frac{d\theta}{dz}$$

Q = Heat Flow (W)

λ = Thermal conductivity (W m^{-1} K^{-1})

A = Cross sectional area (m)

$\frac{d\theta}{dz}$ = Temperature Gradient (°C m^{-1})

θ = Temperature (°C)

z = depth (m)

The thermal conductivity and thermal gradient are both used, either through direct measurement or averaged from heterogeneous media (e.g. in formations that consist of thinly interbedded sandstone, mudstone and siltstone, thermal conductivity will be an average of these layers), to determine heat flow. In its simplest form the equation considers conduction only: the rate of heat flow is governed by the size of the temperature difference, the length over which the heat has to travel, the size of cross sectional area and the time period over which the heat travels. Convection also plays a part in distributing heat as will be seen further on within this Chapter.

2.1.1.1.1 Heat Flow in the Lithosphere

Heat flow distribution differs between oceanic lithosphere and continental lithosphere. Huenges (2010) states that of the 46 TW of heat that is lost from the Earth, "only 14 TW is released over continents" (approximately 30%); the remainder is released through oceanic crust. Average continental crustal geothermal gradients are approximately 26°C km^{-1} (Selley and Sonnenberg, 2015), giving temperatures up to 260°C at 10 km depth. If the gradient were extrapolated further, however, unrealistic temperatures within the Earth's core would be obtained, and as such there are clearly other processes occurring that disturb the temperature gradient and distribute heat. In addition, there are areas within continental crust that may have much elevated or much suppressed geothermal gradients indicating further processes (such as convection) and properties (vertical and lateral heterogeneity of lithologies) are affecting the distribution of heat.

Oceanic lithosphere heat flow mirrors mantle heat flow as it is essentially part of the convective cells known to exist within the mantle. The formation of new oceanic crust at divergent plate margins coincides with upwelling hot mantle, whilst subducting oceanic crust mirrors the downwelling part of the same convection cell. At plate-forming margins, high heat flows are seen, as shown on Figure 2-2.

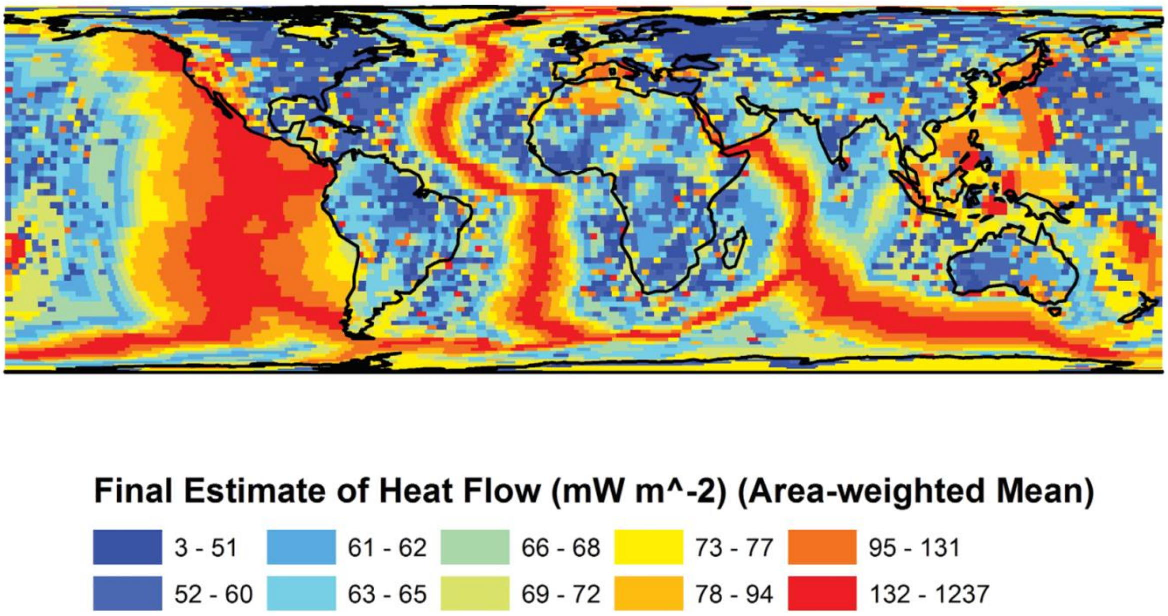


Figure 2-2: Global heat flow map (Davies, 2013), showing high heat flow coinciding with oceanic crust-forming plate margins, decaying with distance perpendicular to the ridge axis.

Heat flow decays exponentially with distance away from the plate boundary; oceanic lithosphere propelled away from these margins sees a similar decrease in its heat flow towards subduction zones. Heat flow readings in oceanic lithosphere reflect this heat loss with maximum heat flow being recorded at divergent plate boundaries and minimum heat flow being recorded at subduction zones. In addition to this difference in heat flow, oceanic lithosphere is relatively depleted in radioactive elements and therefore has no independent method through which it can generate heat. Constraining upper and lower thermal boundaries within oceanic lithosphere can therefore be undertaken more readily and with more accuracy than from continental lithosphere.

Unlike oceanic lithosphere, continental lithosphere does not provide a well constrained thermal boundary with mantle heat flow. Continental lithosphere thickness varies widely which imparts an important effect on the distribution of heat flow from the mantle. In addition to the thickness variation, continental lithosphere is relatively enriched in heat generating radioactive elements unlike oceanic lithosphere; continental lithosphere has the capacity to generate heat independently of mantle heat. This makes prediction of thermal gradients from ground level to the base of continental lithosphere problematic. Heat flow readings taken from ground level show variation across continents, with lower readings being found to exist in central areas of old continental cratons. Values taken from continental margins show an increase in heat flow due to crustal thinning. In addition, the input from igneous intrusions, mineral intrusions and insulating effect of basins modifies heat flow. The mineralogy of a vein is typically very conductive and produces an increase in surface heat flow. However, measured subsurface temperatures are relatively unperturbed. Large sedimentary basins can display an opposite effect, whereby heat flow is not seen to 'spike' across the location of the basin, but temperatures can be enhanced. Figure 2-3 shows these effects schematically.

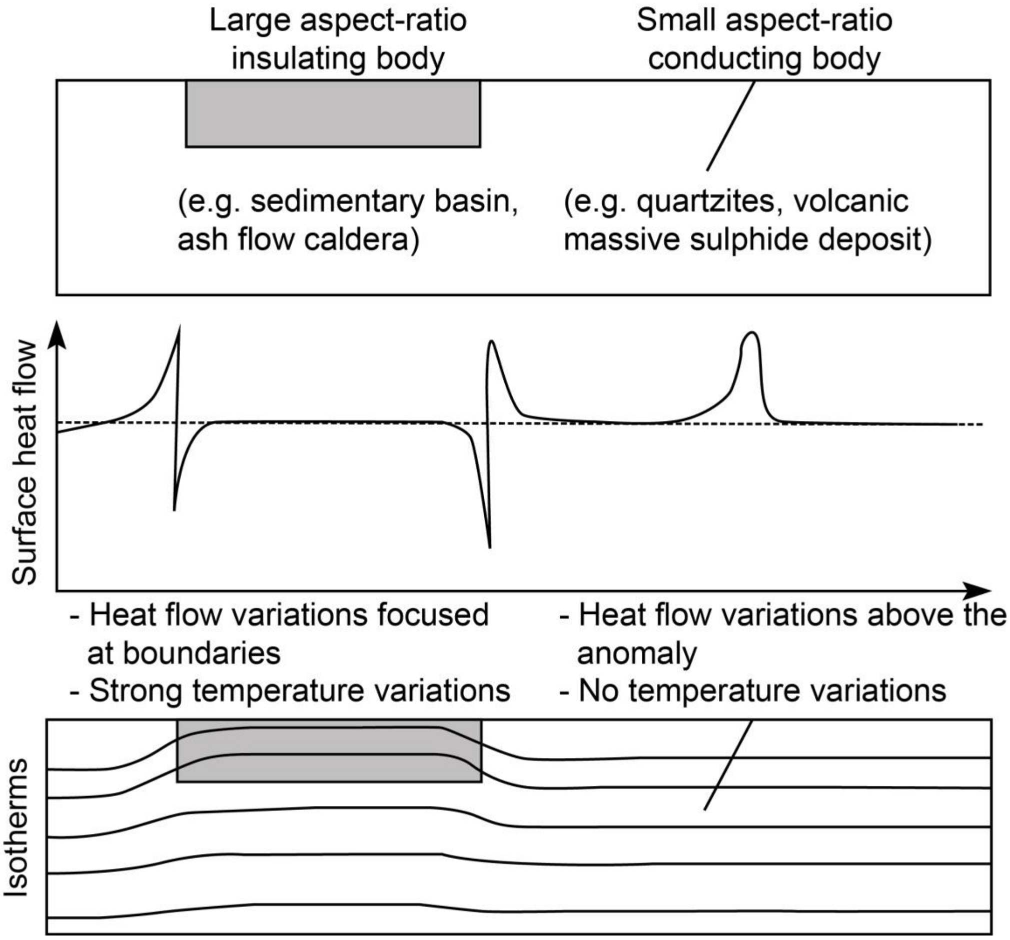


Figure 2-3: Taken from Huenges (2010), this figure shows how a small conducting body and large insulating body can have opposing effects on heat flow and temperature.

These effects are important as it begins to describe more of the complexities involved in predicting geothermal trends over large areas.

2.1.1.2 Fourier's Law: Thermal Conductivity

Thermal conductivity is the capacity of a material to transmit/conduct heat. The heat is transferred by phonons (or lattice vibration waves); the sum of lattice conductivity and electron conductivity defines the thermal conductivity. Substances with low thermal conductivity do not transmit heat rapidly, and therefore have a correspondingly high geothermal gradient. Materials of high thermal conductivity transfer heat rapidly, and have a correspondingly low geothermal gradient. The thermal conductivity of a material is affected by the structure and temperature of the material. The orientation of a purely crystalline sample can yield different values of thermal conductivity depending on the orientation the sample was placed when measured. Different crystal axes will transmit phonons at different rates. Further to this, crystalline rocks scatter phonons in a more irregular manner, which in turn dissipates heat more readily and they therefore have a correspondingly higher thermal conductivity. Compared to porous media, where air-filled pores provide effective insulation, a correspondingly lower thermal conductivity is measured. The thermal conductivity of various major UK formations is presented in Table 2-1. These values are mean values from published datasets, compiled together by Wheildon and Rollin (1986). For reference, UK granites have average values ranging between 3.32 $Wm^{-1}K^{-1}$ and 3.24 $Wm^{-1}K^{-1}$.

Measuring thermal conductivity in crustal rocks at a reasonable resolution can be problematic given the scale over which the measurement is taken. Wheildon and Rollin (1986) discuss the sampling frequency of a 300 m borehole to produce a high quality thermal conductivity value. Where average samples are 10 mm taken at 10 m intervals, this provides a “good” quality thermal conductivity measurement. However, thermal conductivity can be affected by heterogeneity on an individual crystal scale through to mm-scale compositional variation. In complex sedimentary and metamorphic systems, sampling must be increased to reflect these heterogeneities. Formations may contain several lithologies, each of differing composition and therefore thermal conductivity. Assigning a single thermal conductivity value to a formation can include values from 1-4 $Wm^{-1}K^{-1}$. Table 2-1, therefore, provides a best estimate for average thermal conductivity but must still be treated with caution.

Table 2-1: Thermal Conductivity data for major lithologies found across the UK taken from Downing and Gray (1986a). anhy = anhydrite; chlk = chalk; hali = halite; lmst = limestone; mdst = mudstone; sdst = sandstone; slmd = silty mudstone; slst = siltstone; smst = sandy mudstone.

Era	Formation	Lithology	Thermal Conductivity $Wm^{-1} K^{-1}$
Paleogene	Barton Beds	smst	2.12
		mdst	1.46
	Bracklesham Beds	smst	2.2
		mdst	1.58
	London Clay	smst	2.45
	Reading Beds	smst	2.33
		mdst	1.63
Cretaceous	Chalk	chlk	1.79
	Upper Greensand	sdst	2.66
	Gault	smst	2.32
		mdst	1.67
	Hastings Beds	slst	2.01
		slcl	1.26
Jurassic	Kimmeridge Clay	mdst	1.51
	Ampthill Clay	mdst	1.29
	Oxford Clay	mdst	1.56
	Kellaway Beds	mdst	1.52
	Cornbrash	lmst	2.29
	Forest Marble	mdst + lmst	1.8
	Frome Clay	mdst	1.72
	Fullers Earth	mdst	1.95
	Upper Lias	sdst	2.87
		mdst	1.27
		slmd	2.22
	Middle Lias	mdst	1.66
	Lower Lias	mdst	1.8
Rhaetic	Penarth Group	slmd	2.53
Triassic	Mercia Mudstone Group	mdst	1.88
	Mercia Mudstone Group	mdst	2.28
	Sherwood Sandstone Group	sdst	3.41
		mdst	2.37
Permian	Permian Marls	marl	2.12
		anhy	5.4
		hali	4.87
	Magnesian Limestone	lmst	3.32
Carboniferous	Westphalian	sdst	3.31
		slst	2.22
		mdst	1.49
		coal	0.31
	Namurian	sdst	3.75
	Tournasian	lmst	3.14
		sdst	4.19
Devonian	Old Red Sandstone	sdst	3.51
Lower Palaeozoic		variable	2.87

2.1.1.3 Fourier's Law: Geothermal Gradient

The rate of temperature increase with depth defines the geothermal gradient parameter of Fourier's Law. The average temperature gradient across the world is approximately 26°C km^{-1} (Selley and Sonnenberg, 2015); specifically within the UK it is also 26°C km^{-1} (Busby, 2014). There are areas that can be much elevated or reduced above or below the UK average. Areas where elevated temperature gradients exist can coincide with zones of high heat flow, such as those found concentrated along active tectonic margins and in areas where the Moho is at a shallower depth (Busby, 2014). In tectonically stable areas, however, heat flow may not be elevated yet the temperature gradient can still be elevated. These elevated temperature gradients can relate back to the fact areas consisting of large insulating bodies do not show a marked change in heat flow, yet can have a more disturbed geothermal gradient, as per Figure 2-3 after Huenges (2010).

The timescales over which geothermal gradient is assessed is an important consideration. Heat flow and the global geotherm are constantly being perturbed in some manner, but some of these processes occur over many millions of years, whilst others reflect events that occurred within the last 10,000 years. Large-scale rifting at both continental and oceanic margins disturb the geotherm, and the effects are far reaching both in time and space. These large-scale disturbances in heat flow and temperature are not of interest as part of this thesis, and can be valued as a constant given the timescale over which these disturbances are prevalent. There are other ways in which heat is trapped, generated or dissipated to produce a geothermal anomaly within continental lithosphere that occur over much shorter timescales and impact directly upon geothermal energy assessments. These are further discussed within Section 2.2.

2.1.2 Temperature Measurement Methods

The measurement of temperature is undertaken within a borehole, whilst thermal conductivity is measured from cuttings taken from within the bore. Measurements of temperature have always been of interest. Initially it was due to the impact of temperature on safe working conditions during mining operations (Prensky, 1992). More recently understanding temperature gradients and prediction of temperature at depth has many applications, from oil and gas exploration to understanding plate tectonics and crustal evolution. It can also be used to determine fluid movement within a borehole (Prensky, 1992). This thesis has no scope to access boreholes and take independent temperature measurements as it uses existing data taken from various industries. However, it is still important to have an understanding of the method of measurement, and the quality of measurement, before using these data in geothermal applications. Erroneous data / poor quality can lead to over or under estimation of geothermal gradient and ultimately geothermal resource value. Recognising these data will ensure they can be discounted from calculations and provide a more robust dataset.

Temperature is measured using a dedicated wireline downhole logging tool that produces a continuous measure of temperature throughout the length of the bore. The running of these standalone wireline logging tools is becoming less prevalent, however, and it is more likely that temperature is a secondary parameter that is measured by a wireline logging tool that has a primary measuring function (such as callipers, resistivity, gamma ray, neutron density). In particular, a resistivity tool requires a measure of temperature to produce a complete analysis of the data. Early measuring techniques involved hand operated maximum reading mercury thermometers and/or electrical resistance apparatus before Schlumberger developed a method of continuous measurement throughout a borehole. These tools are limited, however, as they cannot be used in high temperature (or high pressure) wells. Depending on the temperature of the fluid within the borehole the temperature probe may need to be modified to withstand the hostile conditions at the base of the well. Temperatures in excess of 150°C coupled with highly saline fluid and elevated pressures are encountered within some geothermal wells which can cause the failure of the logging tool. An initial solution has been to place the electronics of the logging tool within a Dewar flask, but high pressure-high temperature wells go beyond the capabilities of this method. Standard temperature logging tools are still applicable at temperatures below 150°C which covers the low enthalpy resource that this project aims to assess.

Most temperature measurements are Bottom Hole Temperatures (BHTs), taken when the logging tool is at the bottom of its run and the temperature (in theory) is correspondingly at its highest. In the majority of cases these values are not true representatives of the formation temperature; they represent the temperature of circulated drilling fluid which is of a lower temperature than the formation temperature (Deming, 1989; Förster, 2001). The recording of equilibration temperatures is generally rare due to the time required for the borehole to stand before equilibration is reached. Equilibration temperatures can take anywhere between several days through to years of standing undisturbed before an accurate measurement can be recorded (Bullard, 1947; Oxburgh et al., 1972). This extended period of time is due to the re-equilibration being primarily via conduction as opposed to convection, and subsequently the process occurs at a slower rate. Given that it is not always practical to leave boreholes standing for any length of time, several methods to correct BHTs have been produced.

2.1.2.1 Drilling-Induced Temperature Disturbance and Correction

In the first instance temperature correction is required due to the effect of drilling. Bullard (1947) states two effects of drilling on the temperature measured within a borehole; the heat generated by the drill tool and the addition of drill fluid to aid the drilling process. The circulation of drill fluid is deemed to have a larger corresponding effect on the temperature (the lower part of a bore will be cooled whilst the upper part will be heated). Temperature can be measured during drilling (either MWD - Measurement While Drilling or LWD - Logging While Drilling), or once drilling has ceased. Both will have associated suppressed temperature measurements, the former being of a greater magnitude than the latter (Bullard, 1947).

Correction methods to restore temperature back to the natural gradient have been developed by several authors. Deming (1989) provides a comprehensive comparison of the main methods of BHT correction. Many use an empirical approach to provide a temperature correction, whereas some use mathematical models to describe the temperature change within a borehole. The latter requires more information from the well records and as such can be harder to resolve. The most commonly used mathematical model utilised for temperature correction is the Horner plot. The Horner correction takes the following form (Equation 2-2), after Bullard (1947), c.f. Deming (1989):

$T_{\infty} = BHT + A \log_e[t + t_{circ} / t]$ **Equation 2-2: Horner Temperature Correction**

Where T_∞ is equilibration temperature, A is an unknown constant, t is the shut in time and t_{circ} is the drilling mud circulation duration. The Horner method has its limitations, as it requires at least two BHT measurements at the same depth but at differing values of t. Two values are also required to plot a time-temperature set. The gradient of the produced plot provides a value for the unknown constant A. Difficulty with the Horner correction method arises as t_{circ} is not always noted on drilling logs, thus making a requirement for a standard circulation time to be applied to the equation (noted to be 4 or 5 hours by Deming, 1989). In general the amount of data required to calculate the temperature correction is rarely noted during drilling. However, these drawbacks are very much practical rather than mathematical. The method, if it can be applied, forms a robust way to correct temperatures.

Other empirical methods of calculating a temperature correction can also be utilised. These methods use a mix of BHT, Drill Stem Test (DST) data and equilibrium temperature measurements to calculate a correction factor. However, these correction factors restrict a temperature correction factor to a particular locality or field as it is only utilises well data across that particular area. Corrections for the North Sea (Andrews-Speed et al., 1984), Tunisia (Ben Dhia, 1988), specific areas of North America (Förster and Merriam, 1995) and the Gulf of Mexico (Waples et al., 2004) have been produced. Waples and Ramly (2001) used data from the Malay Basin to produce a correction factor, and stated the correction was likely applicable to other geological settings. However they do concede that further calibration data from the area of interest would be desirable to better constrain the correction factor.

2.1.2.2 Natural Disturbances of the Geotherm

The drilling process forms one way in which temperatures can be modified. Natural processes can also modify the flow of heat in the upper reaches of the crust where the heat flow and temperature are affected at depth such that it deviates away from what might be expected.

2.1.2.2.1 Topography

It has been recorded that variations in topography affect lateral heat flow. An increase in heat flow is seen beneath valleys whilst a decrease is seen beneath the hills separating the valleys (Westaway and Younger, 2013). This increase/decrease effect has been assessed in some areas around the world, but within the UK heat flow dataset it has not been fully taken into account. The correction is important if temperature below the depth of measurement is to be estimated. Whilst some authors state the effect of topography on heat flow is negligible below 100 m (Richardson and Oxburgh (1978) c.f. Westaway & Younger, 2013), it was shown by Bloomer et al. (1979) (c.f. Westaway & Younger, 2013) that two boreholes located on the valley bottom within areas of severe topographic relief had the largest applicable heat flow correction value. The topographic heat flow correction proposed by Westaway and Younger (2013) cannot be arbitrarily applied across the UK as it depends and the particular valley shape in question and the 3D nature of the valley also. The largest corrections are applied to areas of high relief; lower lying areas will have a smaller correction. Within this study the study areas are both in reasonably low topographic relief. In addition temperature has been taken directly from drilling logs. It does not utilise heat flow measurements taken from shallow boreholes which have then consequently been extrapolated to estimate temperatures at depth. The effect of topography on temperature and heat flow within this project has therefore been omitted.

2.1.2.2.2 Climate Effects

The effects of Quaternary glaciation events are still seen across the UK today; subsurface heat flow can still be suppressed. During periods of glaciation the corresponding air temperature is reduced to arctic levels. These periods of glaciation persisted long enough to cause an appreciable effect on surface and shallow heat flow. The depth to which the effect of past climates penetrates can be several hundreds of metres (Banks, 2008; Westaway and Younger, 2013; Wheildon and Rollin, 1986). In previous UK geothermal studies, many deep temperature estimates have been based on extrapolations of shallow heat flow and temperature measurements from boreholes typically 100-300 m depth. These extrapolations were not corrected for paleoclimate, even though the authors acknowledged temperatures would be suppressed (Westaway and Younger, 2013). In some cases authors have attempted to correct for the effect of paleoclimate but underestimated the magnitude of such a correction. Wheildon and Rollin (1986) state the effect below 300 m is negligible and, therefore, can be omitted. Rollin (1995) estimated the temperature perturbation in a 320 m borehole would be no more than 10%, and the effect in boreholes >1000 m would be negligible. However, the correction was undertaken assuming a surface temperature change of 2°C, something shown to be likely well underestimated by Westaway and Younger (2013). They also reason that due to uncertainty in the timing of temperature perturbation, and the magnitude, this has also led to some authors omitting the correction completely. The UK geothermal dataset is, on the whole, an uncorrected one. In work undertaken by Wheildon and Rollin (1986), using uncorrected values was justified by their use in a comparative study only. However, geothermal resource estimates were then based on these temperatures producing a contradiction and ultimately an under-representative value.

A recent comprehensive study on the UK geothermal database suggests heat flow can be suppressed such that extrapolated heat flow require a paleoclimatic additional correction of up to 27 mWm^{-2} (Westaway and Younger, 2013). The correction value reduces with depth and with variation in depth range utilised for the correction. The correction is not consistent across the UK, and a site by site assessment is required. The insulating nature of ice sheets is something previously not taken into account but is of importance. Areas covered by ice sheets require a smaller correction to be applied than those exposed directly to the atmosphere. For instance, some locations in Canada are colder now than they were during the Last Glacial Maximum (LGM). Conversely, areas within southern Britain that were not covered by ice during the LGM are warmer now than they were then, and thus require a larger correction to be applied.

The application of a paleoclimate correction to a geothermal dataset falls somewhat outside the remit of this project despite the impact it can have. Paleoclimate corrections require an understanding of surface temperature during previous glacial and interglacial periods, something which is ascertained through analysis of temperature-sensitive flora and fauna, biostratigraphy and oxygen isotope data. It is known that ice is unlikely to have covered the East Midlands during the LGM (Clark et al., 2012; Lee, 2011), so whilst the corresponding correction will be large, it also means temperature estimates could also be viewed conservatively. The Cheshire Basin and East Irish Sea Basin were, however, likely covered by ice and the corresponding correction is likely to be smaller as a result.

2.1.2.2.3 Convective Flow / Groundwater Movement

Heat can be re-distributed by circulating groundwater flow that can disturb heat fluxes and create anomalies on a regional scale. The effect of flowing groundwater can be seen on wireline temperature logs and shows not only a drop or rise in temperature to above/below what might be expected, but also shows flowing horizons. Being able to highlight flowing horizons is particularly important as it is noted that even small fluid velocity movements within a geothermal resource can modify estimated temperatures at depth. Kappelmeyer (1979) showed a seepage velocity of 0.3 ma^{-1} across a 1°C temperature variation can alter surface heat flow by 42 mW m^{-2} (Wheildon and Rollin, 1986), which translates to a temperature alteration of approximately 150°C at 9.5 km depth.

Heat flow within the Western North Sea was assessed by Andrews-Speed et al. (1984), where geothermal gradient and thermal conductivity taken from petroleum wells were used to produce heat flow values of the upper 1-2 km of crust. Whilst heat flow was observed to increase with depth within the Central Graben and Anglo-Dutch basin, a reversal was seen on the East Midlands shelf and Mid-North Sea high (a decrease from 80 mW m^{-2} to 50 mW m^{-2}). The decrease in heat flow was attributed to large-scale circulation of fluid within the basin. Simple models for predicting geothermal gradients are therefore inadequate if there are small seepage velocities. An adequate understanding of fluid movement within any given basin is therefore of high importance if accurate modelling of heat flow is to be undertaken.

Heat flow can be used as a method to identify areas that convective flow is occurring: these anomalous results will clearly stand out. Areas of enhanced and suppressed heat flow indicate areas of upwelling or downwelling fluid. However, as Wheildon and Rollin (1986) indicate, the majority of heat flow measurements taken across the UK assume conductive heat flow only. They recommend that heat flow values taken from sedimentary rocks across the UK should be regarded as apparent heat flow. The implication for temperature variation caused by this disturbance may affect temperatures within this project, but without a comprehensive understanding of the groundwater systems in the area of interest it is thought better to exclude any corrections to account for convection at this stage.

2.2 Geothermal Resource Classification

2.2.1 An Overview

"*A geothermal system is any localized geologic setting where portions of the Earth's thermal energy may be extracted from natural or artificially induced circulating fluids transported to a point of use. Enhanced Geothermal Systems are portions of the Earth's crust where the ratio of flow rate and fluid temperature is naturally too low for economic use, and therefore the flow rate must be increased to a sufficient flow rate/temperature ratio by enhancing the natural permeability through technological solutions*" (Moeck, 2014).

The above definition of a geothermal system summarises neatly the key aspects of what makes a geothermal resource. The definition is purposely broad to reflect the complexities associated with such resources; geothermal resources occur in a wide variety of settings, unlike hydrocarbon systems that can ultimately be defined by source, seal and reservoir (Moeck, 2014). As such, classification of geothermal systems is correspondingly more complex.

Classification of any resource is important; they not only determine the resource based on its geological/physical/chemical properties, but also place the resource in an economic context and allows cross comparison between resources. It was stated by Tryggvadottir (2013) that a Geothermal Reporting Code is not there to provide the methodology of quantifying a geothermal play; it is there to standardise the terminologies used to report results from geothermal exploration and resource/reserve estimates to the public. Using standard terms helps improve confidence in the industry from not only an investor's point of view, but from the public also. It allows resources to be objectively compared.

Geothermal resource exploration, classification and exploitation currently lack a formal set of guidelines that can be applied globally. Assessment and development of new resources can be hindered by lack of classification system because of the lack of consistency in using standard criteria to describe these systems around the World. The lack of consistency in turn hinders the ability to compare geothermal energy with other energy resources (both renewable and non-renewable). Classification systems to date have wide and varied approaches and their applicability to geothermal systems depends on what the document intends to do. Falcone and Beardsmore (2015) state "The authority of a classification system depends on whether it is presented as a reporting standard, a set of rules, a set of guidelines, a set of definitions, a code or a protocol."

Falcone and Beardsmore (2015) state two reasons as to why the global comparison of geothermal resource potential is problematic:

1. Experience gap – geothermal energy is not a common resource to exploit in many areas, and the national agencies in question have little experience in how to assess, characterise, report, compare and exploit these resources. These countries may look to other areas that have successfully exploited a geothermal resource and apply the same economic and technical feasibility to their own resource, leading to over estimations and ultimately fractious relations between government, the geothermal industry, funding bodies and potential investors (especially where an over-estimation of resource has been used to attract investment). In addition estimations of resource size vary amongst experts, the result of which ends in investors, government and funding bodies having low confidence in geothermal energy as an energy opportunity.
2. Where resources have been classified it has been done so using a specific set of criteria that may not be appropriate for any/many other geothermal settings. The terminology and methodology adopted in these assessments may be not comparable, or may be misleading, if attempts are made to apply the same assessment to other areas.

A comprehensive summary of past attempts to classify geothermal systems has been undertaken by Falcone and Beardsmore (2015), based on previous work by Falcone et al. (2013), which should be referred to for a more comprehensive overview. The categories used are presented below with a brief overview of pros and cons of the proposed method.

1. *By accessibility and discovery status*. Here Muffler and Cataldi (1978) define the resource as "all the thermal energy in the Earth's crust beneath a specific area, measured from local mean annual temperature". It is defined further on terms used in a McKelvey diagram, as seen in Figure 2-4 (Muffler and Cataldi, 1978).

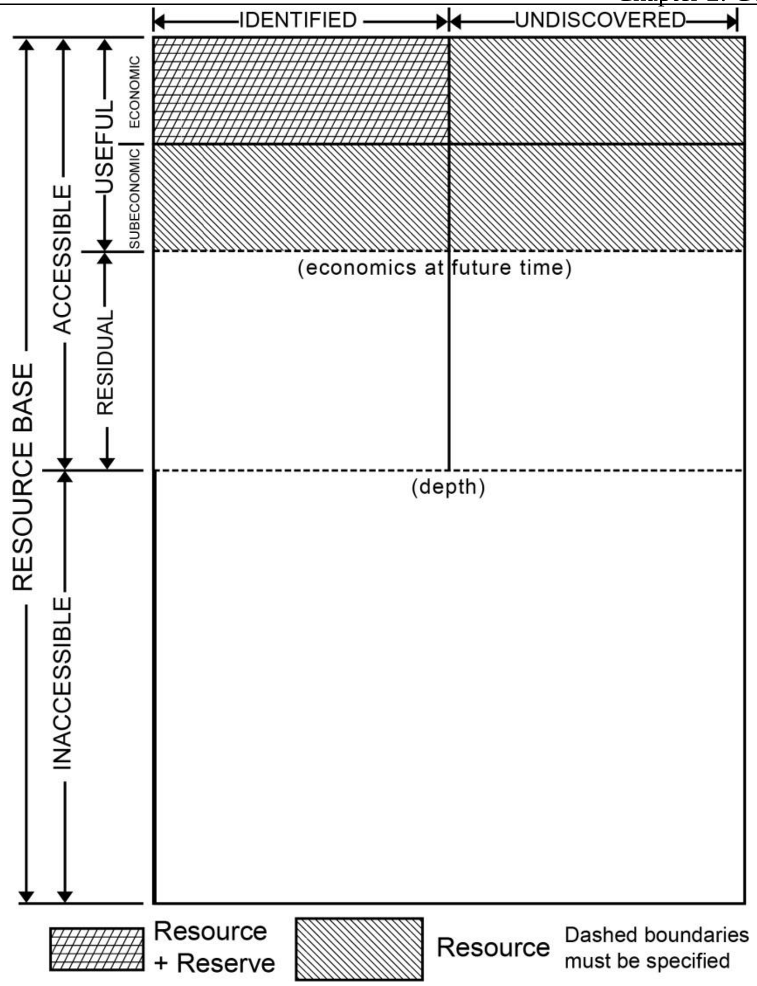


Figure 2-4: McKelvey diagram that describes geothermal energy (Muffler and Cataldi, 1978)

It can be seen from the diagram that only a small fraction of the overall resource base can be exploited, termed the "useful (sub)economic" resource.

2. *By temperature, use, type and status*. Here temperature cut-offs are used to determine the best economic use of the resource. In addition, end use, type and status are utilised. However, this simplistic method fails to recognise other critical factors that may affect the resource development (such as permeability). This method will be discussed further within Section 2.2.3.
3. *By 'Potential'*. where 'theoretical potential' is defined as the total heat in place, and 'technical potential' is how much of the theoretical potential can be extracted based on the technical limits of current technology (Rybach, 2010). Further terminology is used describing further parts of the resource, presented in Figure 2-5. The use of 'Potential' has been further refined to describe EGS systems. Two drawbacks come with using this system. Firstly, it uses the term 'potential' that can be defined based on the terms in Figure 2-5. If this is misreported it can cause confusion. Secondly it

requires a recovery factor for the target rock volume but there are very few data to use within the literature.

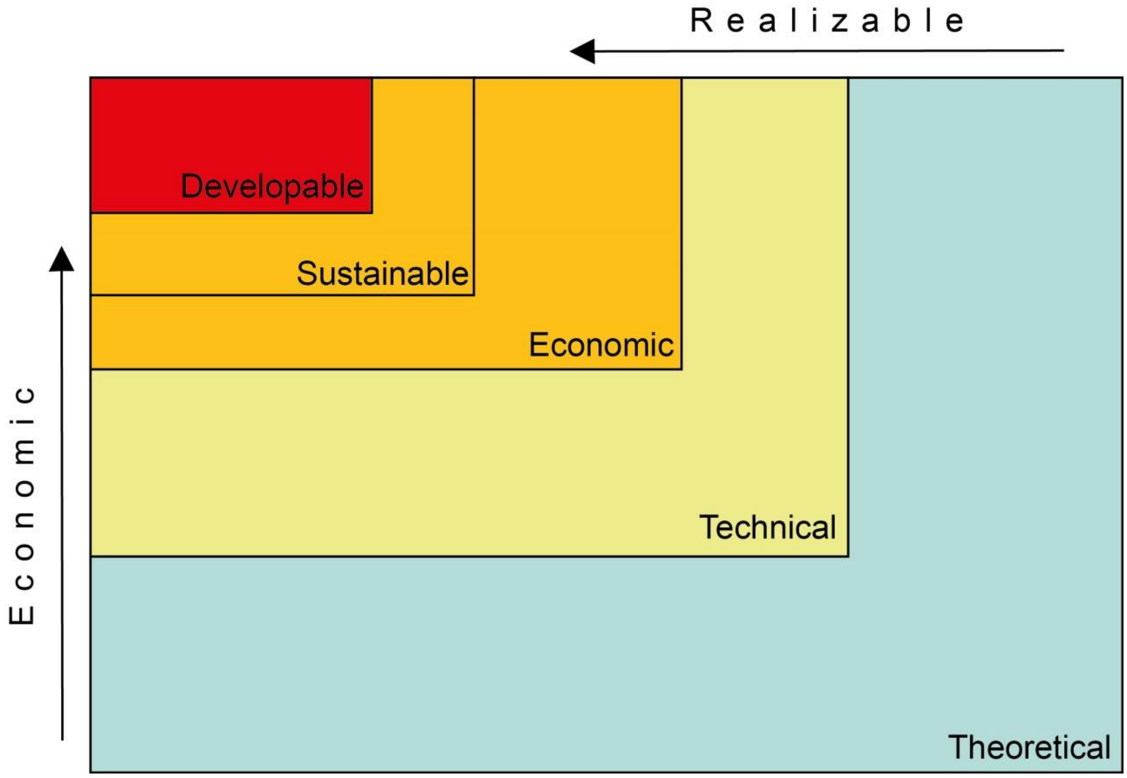


Figure 2-5: Classification of geothermal resources by 'potential' (Rybach, 2010).

4. *By stored heat*. Heat-in-place is calculated based on the thickness, areal extent, temperature, porosity, density, specific heat capacity and physical fluid properties. The drawback of the stored heat method is due to lack of understanding by non-specialists with regards the reported values. Stored heat is a generally a large figure but can be mistaken as the recoverable energy. Stored heat and recoverable heat were further defined by the Australian Geothermal Reporting Code (AGRCC-Australian Geothermal Reporting Code Committee, 2010a) as a result of the stored heat classification method. It is still a useful method when little is known about the method of recovery.
5. *By electric power generation potential*. A method of calculating electrical power generation that relies on power plant life, power plant capacity factor, energy conversion factor and recovery fact. The latter parameter is not well defined which produces a large amount of uncertainty with the method. It also uses the term 'potential', but not in the same context as that used in Category 3 above.

6. *By exergy*. A method that assesses the quality of the energy contained within recovered geothermal fluids, avoiding potential ambiguity when using temperature alone. The exergy method mirrors the hydrocarbon industry and their use of calorific value to classify some fossil fuels.
7. *By geological confidence and 'Modifying Factors'*. Based on a mineral ore reporting code, this system assigns three levels of geological confidence to a geothermal resource (inferred, indicated and measured), and two levels to a geological reserve (probable and proven). The latter relies on 'Modifying Factors' which are economic, environmental and political factors. The geological confidence/'Modifying Factors' method has been employed by the Australian Geothermal Reporting Code Committee and Canadian Geothermal Code Committee, discussed further in Section 2.2.2.

Other methods exist in addition to listed categories above. The above list aims to provide a sense of how classifying geothermal resources is not a simple straight-forward process. The topic of resource classification will be further discussed based firstly around the existing broader-scale international classification systems in existence, followed by further discussion of the classification systems that have been used within this project.

2.2.2 International Classification Systems

As stated within the introduction of Section 2.2 a global geothermal reporting code does not exist, although attempts are now being made to produce such codes. The first international body to recognise the requirement for a geothermal-specific reporting code was the Australian Geothermal Energy Association (AGEA). The Australian Geothermal Reporting Code Committee (AGRCC) defined a Geothermal Reporting Code in 2008 (updated in 2010), stating all members of the AGEA were to report their geothermal exploration, resource and reserves using the Geothermal Reporting Code (AGRCC-Australian Geothermal Reporting Code Committee, 2010b). The Code is based on the Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves (the 'JORC' code), with three levels of resource (inferred, indicated and measured) and two levels of reserve (probable and proven), seen in Figure 2-6.

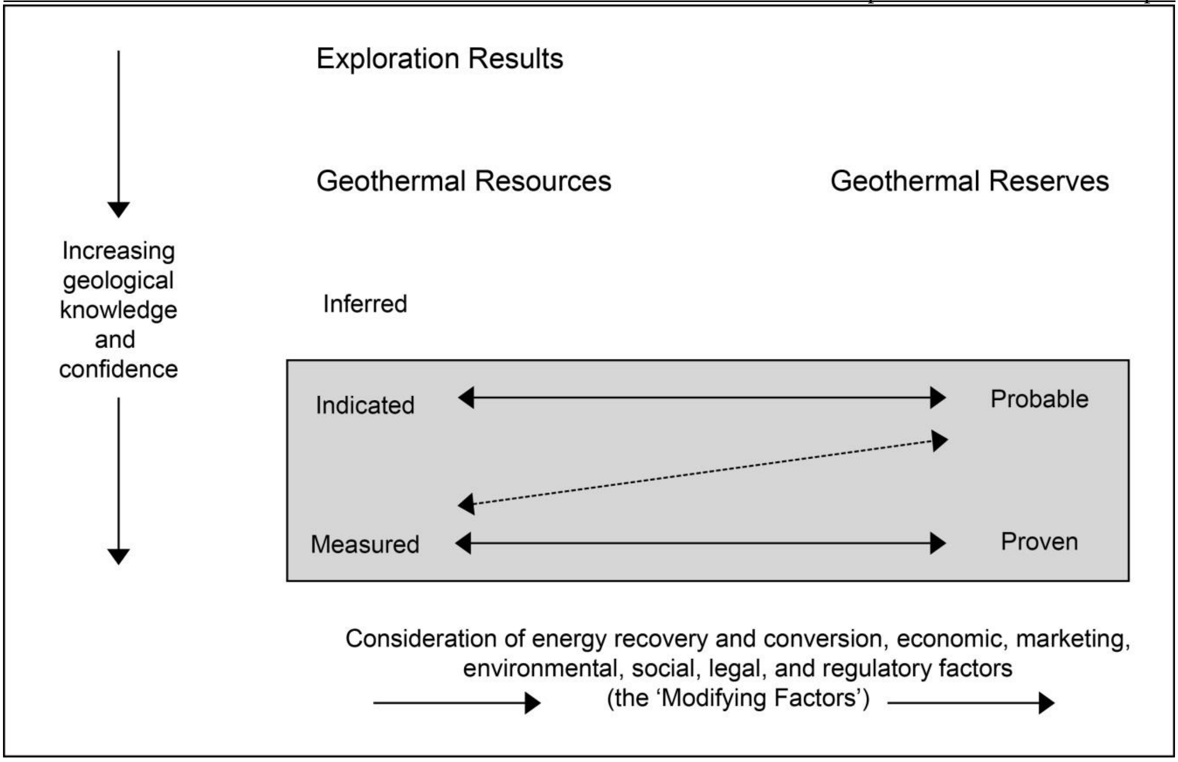


Figure 2-6: The AGRCC-Australian Geothermal Reporting Code Committee (2010b) method of classification, indicating the relationship between resource and reserve terminologies. "Modifying Factors" are combined with the likelihood of the Geothermal Resource being present to qualify a Geothermal Reserve as either being Probable or Proven.

Canada followed Australia's lead and created a similar geothermal reporting code, also based on their respective minerals industry code. In both cases the Code's in question have mandatory requirements that must be adhered to when reporting geothermal estimates. Members of each organisation agree to these mandatory conditions. However, some of the terminology used within the lexicon (AGRCC-Australian Geothermal Reporting Code Committee, 2010a) is not succinct and leaves room for subjectivity. In addition it also relies on a recovery factor which is not widely reported. Despite being billed as a country-specific Code, they have some applicability to geothermal systems worldwide. However, neither Code has been adopted widely by industries across the World. In addition, neither code carries the same law implications with the Australian and Canadian Securities Exchange as the equivalent codes for extractive industries in each country (Falcone and Beardsmore, 2015).

A European Geothermal Reporting Code is under discussion by the European Geothermal Energy Council and GeoElec. A report produced in 2013 by GeoElec (Tryggvadottir, 2013) was produced not only detailing the (then) current situation on geothermal reporting codes, but also offered recommendations for a European-specific reporting code. Arguments for and against the adoption of such a reporting code were put forward within the document. The biggest issue appears to be the lack of an international geothermal umbrella organisation. Whilst the International Geothermal Association (IGA) exists, it is not a regulatory authority on geothermal energy. It is a non-governmental body that encourages "research, the development and utilization of geothermal resources worldwide through the publication of scientific and technical information among the geothermal specialists, the business community, governmental representatives, UN organisations, civil society and the general public". Without a globally recognised regulatory body the implementation of geothermal reporting codes is piecemeal; enforcement of the code is not regulated and (in the case of AGRCC) requires a "Qualified Person" to sign off the work, the effect of which is not monitored. The Code has been used but not quoted in geothermal reports also, so there is no direct compliance with the Code. However, a European-specific code could be seen a stepping stone to not only producing an International Code, but input into that Code by the European Geothermal Council could be made. The recommendation of the report was to wait until further potential users entered the European geothermal market, and in the meantime work alongside the United National Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009 (UNFC-2009) to produce a European-specific standardised set of terminology.

The Geothermal Energy Association (GEA) is the organisation that oversees geothermal in the USA. They chose not to adopt a reporting code due to uncertainty in the legal implications of doing so, but did produce a document titled "New Geothermal Terms and Definitions". The guide was developed to aid resource progress and results, but the terms defined by the guide contradicted those specified by the Australian and Canadian Reporting Codes. The guide produced, however, can be used by the geothermal industry within the US to provide comparable resource quantification.

2.2.3 Project-specific Classification Systems

Within the title of this project, two terms are used that essentially classify the geothermal resource being investigated: low enthalpy resources and deep sedimentary basins. These are specific descriptive terms that fall under classifying a geothermal resource by temperature and by geological setting. Both of these systems have been defined by various authors and classified using different cut off boundaries and terminologies. It is, therefore, appropriate to discuss these systems more fully.

2.2.3.1 Classification by Temperature / Enthalpy

It can be said that temperature is one of the most important criteria for use in classification of geothermal resource. Many authors have classified geothermal resources by temperature/enthalpy, all using either the same or similar terms, but all of which utilise differing temperature cut-offs. Williams et al. (2011) provide a summary of these various cut-offs presented by various authors, displayed in Figure 2-7.

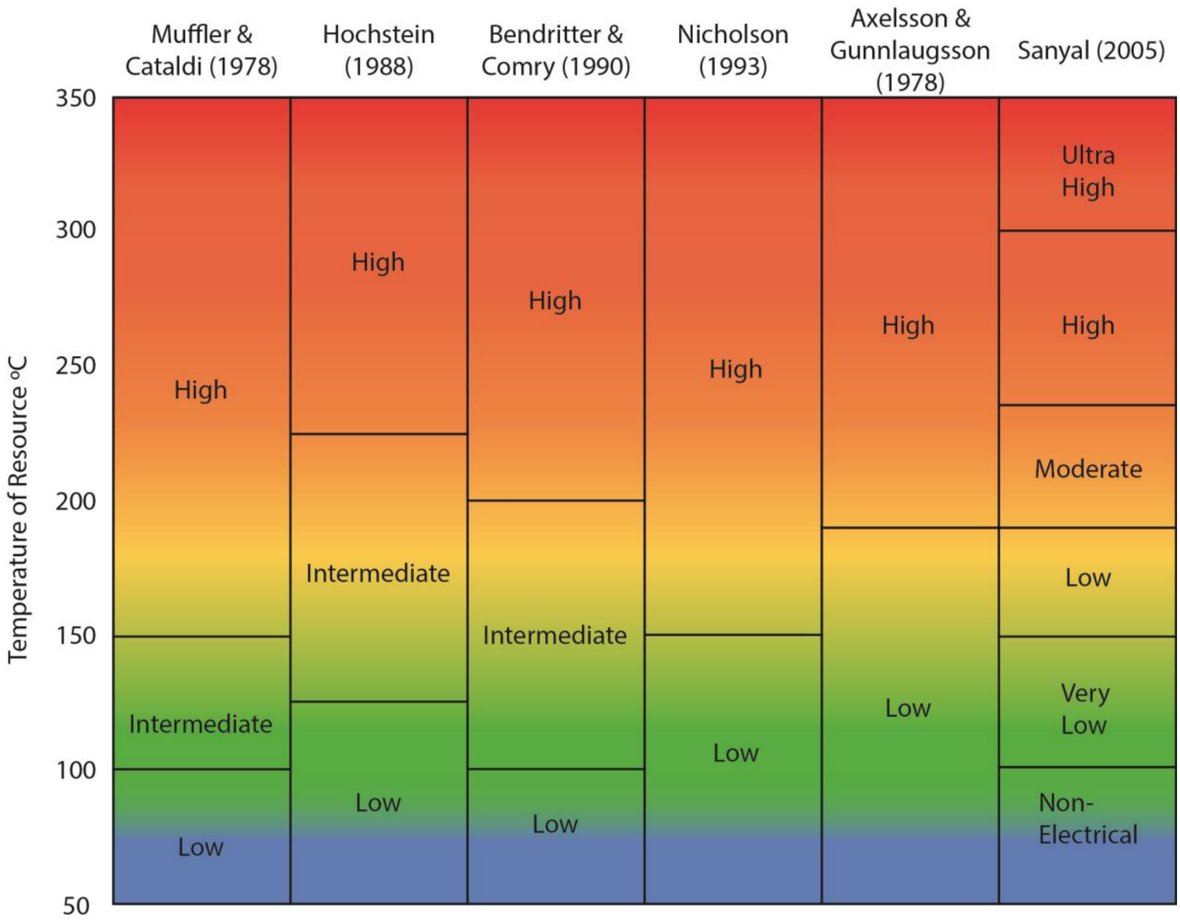


Figure 2-7: Summary of geothermal classification by temperature, after Williams et al. (2011).

Whilst temperature is a primary criterion for classification of geothermal resources, most of these systems take into account other criteria to determine the boundaries. In the case of Figure 2-7 boundaries have also been set based on thermodynamic properties and economic criteria (Williams et al., 2011). Sanyal (2005) in particular incorporates end use (i.e. direct heat-only use vs indirect electrical use) and economic factors such as production mechanism/fluid state, operational problems (such as wellbore scaling) and production technology availability to produce a much more comprehensive breakdown of resource classification. The AGRCC-Australian Geothermal Reporting Code Committee (2010b) does not state what cut-offs to use, only that it should be realistic and taken into account when making an estimation. Within this thesis, the temperature cut-offs offered by Muffler and Cataldi (1978) have been used to describe UK geothermal resources. These cut-offs are closely aligned with other authors who have worked on the UK geothermal resource base. Table 2-2 provides a summary of these cut-offs (geological settings of these temperature classes will be discussed in more detail within Section 2.2.3.2).

Table 2-2: Summary of geothermal resource classification by temperature only

Temperature Class	Temperature Cut-Off	Fluid Phase	End Use
High Enthalpy	>150°C	Vapour and/or liquid	Primarily indirect, secondary direct.
Intermediate Enthalpy	100-150°C	Liquid	Indirect through Organic Rankine Cycle or binary cycle. Direct also.
Low Enthalpy	<100°C	Liquid	Direct only.

High enthalpy systems are typically restricted to volcanically active areas / plate margins where heat flow and temperature gradient are both largely elevated. Water extracted from high enthalpy systems are typically under pressure and at high temperature, and therefore ‘flashes’ on extraction i.e. changes state to produce steam on decompression. The produced steam can be used to turn turbines and produce electricity. The residual heat within the water on condensing can still be as high as 70°C, and can be used as a direct heating source. Once the heat within the water has been depleted to low temperatures (20-40°C), it can be re-injected into the aquifer and left to equilibrate once again. High enthalpy systems tend to form the focus of geothermal exploration because it can be primarily used for electricity production with the residual heat having direct-use applications such as space heating. High enthalpy systems are typically associated with active plate margins, such as those found in Iceland, New Zealand, USA, Italy, Philippines and Turkey. Figures from 2013 for Iceland show 46.7 PJ of geothermal energy was directly used within heating systems, whilst geothermal power plants produced 5.245 GWh electricity (accounting for 29% of total electricity produced). Meanwhile, New Zealand has over 1000 MW_e of installed geothermally produced electrical capacity accounting for 16% of the national electrical generation.

Low enthalpy resources typically form within stable intraplate settings where temperatures range from 40-100°C and heat flow is moderate (50-60 mW m^{-2}, Downing & Gray, 1986a). The resource tends to be within permeable sedimentary units which are more widespread than high enthalpy systems, but are correspondingly more diffuse than such systems. The projects that exploit these settings are for heat only; binary cycles and Organic Rankine Cycles (ORCs) are not efficient enough to produce electricity from water extracted at these temperatures. However, the heat can be used in district heating schemes, pisciculture (fish farming), commercial greenhouses, swimming pools, balneology and buildings that typically carry high heat loads (such as hospitals). Successful stand-alone direct use systems have been utilised in Germany, Iceland, Canada and Southampton, UK.

Intermediate/mid enthalpy systems are systems containing water <150°C but >100°C. These systems still have the potential to produce electricity despite it not ‘flashing’ at these temperatures. A binary cycle or ORC can be employed to aid the process if temperatures fall within this bracket. ORC’s utilise a working fluid with a lower boiling point than that of water. If water is directly extracted from an aquifer it can be pumped through heat exchangers, transferring the heat to the working fluid. Several cycles can be used to ‘ramp up’ the temperature of the working fluid until steam is produced to turn a turbine. If water is not being directly extracted the working fluid can be pumped through a closed network of pipes that penetrate the aquifer where it can be left to equilibrate with the aquifer temperature before being extracted. The efficiency of a binary cycle is key to its success.

Experiments have shown ORCs to successfully produce electricity from water at 74°C in Chena, Alaska (Lund, 2006), which is at odds with the values presented in Table 2-2. Generally the effort required to create power from such low temperature fluids is greater than the economic viability of such a geothermal scheme. The ORC in Chena works well as it can sustain a high flow rate (~2765 m^3 d^{-1}) **and** a large temperature differential (inlet temperature is 74°C, cooling fluid temperature is 4°C). High volume flow rates are difficult to achieve and maintain when relying on the natural permeability of a reservoir. Schematics of each system described above can be found in Figure 2-8.

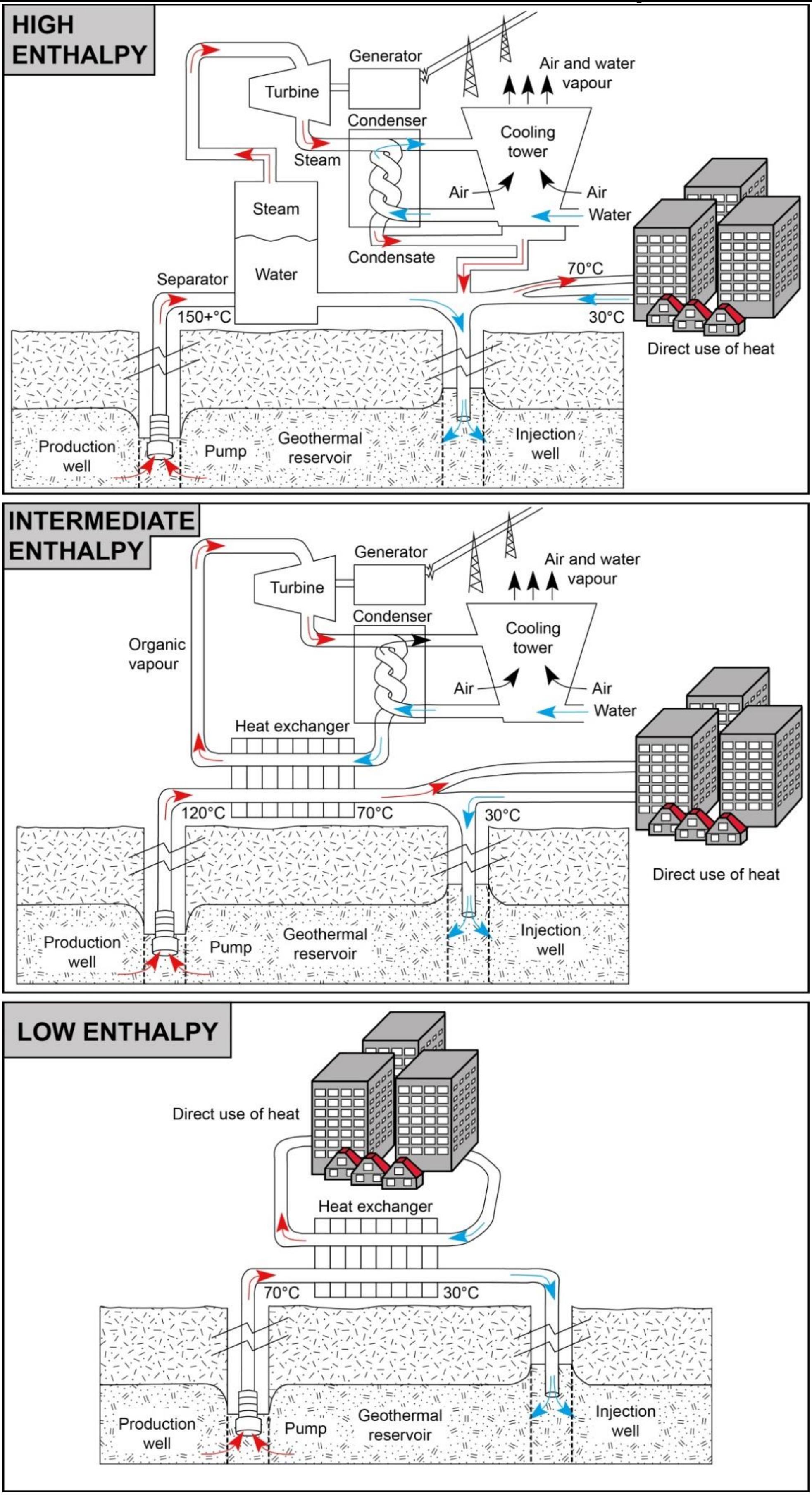


Figure 2-8: Process flow diagrams of low, intermediate and high enthalpy resources with end users (Lund, 2007; Younger et al., 2012)

2.2.3.2 Geological Setting Classification

Describing the geological setting (or geothermal 'play') of a geothermal resource is another way of classifying such systems. Rather than classify by temperature alone, classifying by geological setting introduces the tectonic settings that are prone to high, intermediate or low enthalpy resource occurrence.

Geothermal resources occur in areas where the heat flow and temperature gradient is elevated above what might be expected, typically due to the following (Lund, 2007).

- Intrusion of molten rock from depth (volcanic terranes).
- Crustal thinning due to extension allowing for a high temperature gradient and thus high surface heat flow.
- Ascension of deep circulating groundwater.
- Deep sedimentary basins that have been insulated due to the thermal conductivity contrast of sediments within the basin.
- Heating by radioactive decay within buried granitic bodies.

Moeck (2014) describes a system to catalogue geothermal plays based on geological characteristics, incorporating geological controls and the tectonic setting to determine the thermal regime of the area. In addition, how these geological and tectonic controls affect hydrogeology (including fluid chemistry and fluid dynamics), lithology and geological structures (including stress field) are also taken into account. The ultimate aim of the catalogue described by Moeck (2014) is to create a series of transferable geological 'play-types' which can be identified around the world. The classification scheme is subdivided into convection and conduction dominated 'play-types' as described by Figure 2-9.

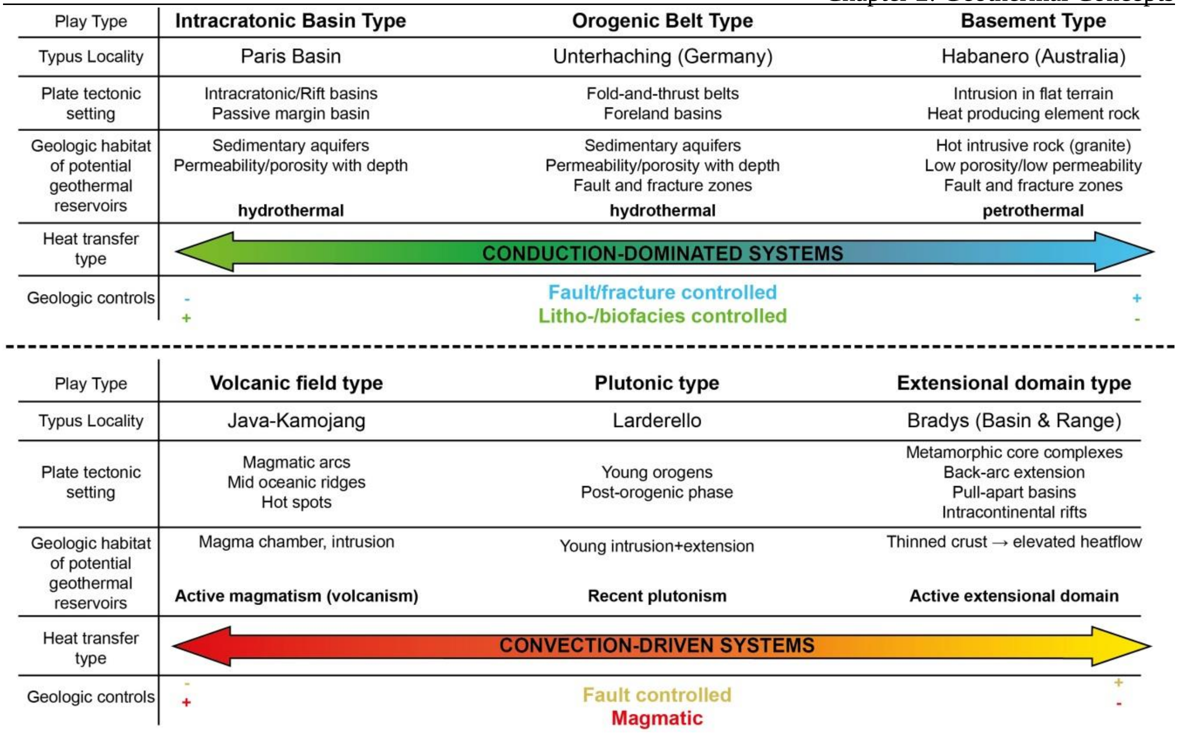


Figure 2-9: Catalogue geothermal ‘play-types’ based upon geological controls, after Moeck (2014).

Low enthalpy resources are related to conduction-dominated systems; UK resources fall under either the Intracratonic Basin Type ‘play’ or Basement Type ‘play’. A further schematic of these systems can be found in Figure 2-10.

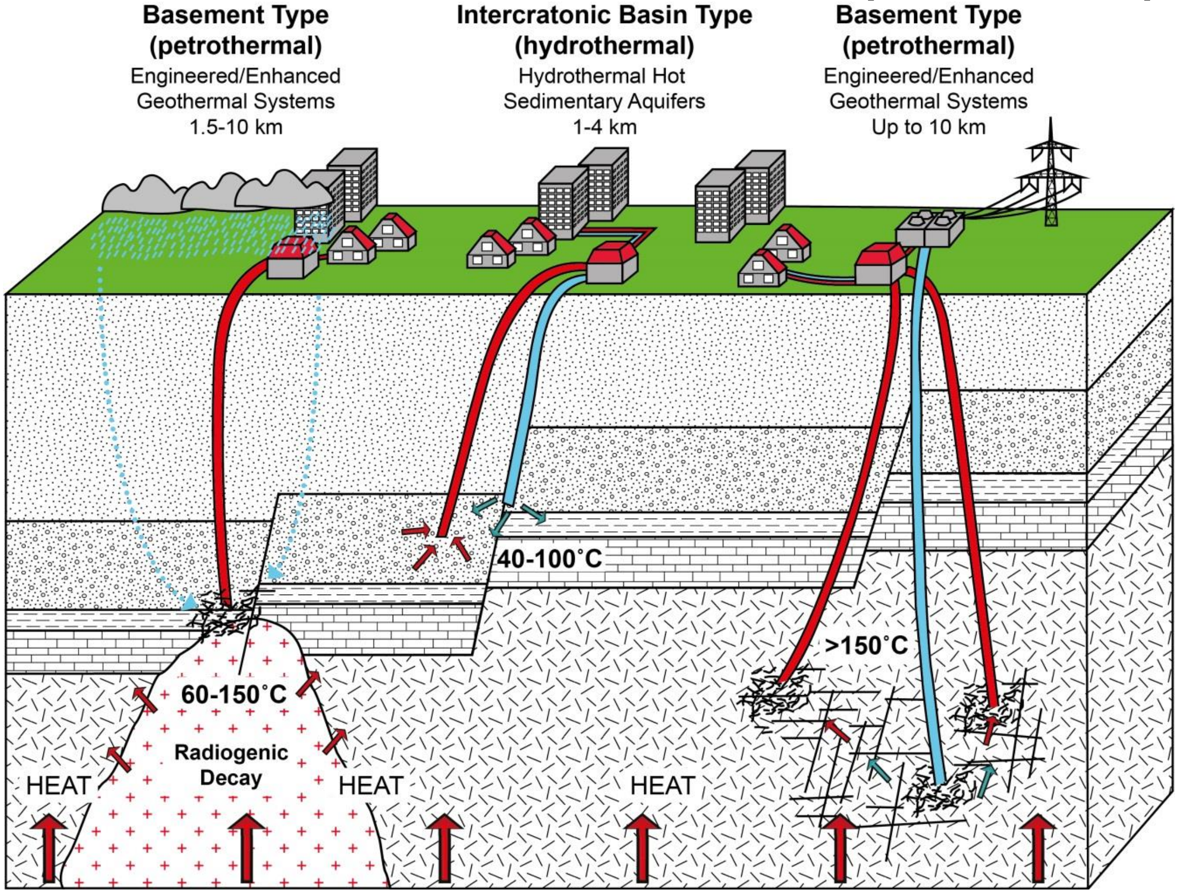


Figure 2-10: Schematic diagram showing major geothermal resource settings, adapted from KIC InnoEnergy (2016).

Other ways of splitting geothermal resource by geological setting have been presented but tend to focus on further categorisation of geological settings that produce high enthalpy resources (predominantly volcanic terranes). Given the lack of such settings within the UK, the classification provided by Moeck (2014) is considered adequate to define geothermal resources by geological setting for this thesis.

2.3 UK Geothermal Prospects

The UK is located on a tectonically stable portion of the Eurasian plate. Minor earthquake activity occurs on a small scale in response to post-glaciation unloading of the crust, and also in response to more general plate movement (British Geological Survey, 2016). As a result the resource within the UK can be classed predominantly as low enthalpy, with scope for mid-to-high enthalpy systems associated with buried radiogenic granite plutons also being possible. Section 2.3 aims to produces an overview of the research previously undertaken, and also discusses the current understanding of geothermal resources within the UK.

2.3.1 History

An assessment of geothermal resource availability within the UK was undertaken between 1976 and 1994 in response to the oil crisis experienced during the 1970's (Busby, 2014). Between 1977 and 1984 contracts from the Department of Energy / Energy Technology Support Unit (ETSU) and Commission of European Communities (CEC) were awarded to the British Geological Survey (BGS) to carry out investigations into quantifying the UK's geothermal resources (Barker et al., 2000; Busby et al., 2011; Downing and Gray, 1986a). The aim of the investigation was to assess the following (Barker et al., 2000; Downing and Gray, 1986a):

- To ascertain and map heat flow across the UK.
- To identify and quantify low enthalpy resources associated with Mesozoic sedimentary basins (basins formed 250-65 million years ago) where hot water at 60°C at 2 km are present. Water at 40°C at 1 km could also be used with these resources with the use of a heat pump.
- To identify and quantify high enthalpy geothermal resources associated with igneous intrusions. Achievable temperatures are 100°C at depths >3 km.

Early work on heat flow was undertaken as far back as 1868 when the British Association formed a "Committee on strata temperatures" and began publishing a series of reports (23 in total) on temperature and heat flow (Barker et al., 2000; Downing and Gray, 1986b). Continued investigation in the 1970's was undertaken that further added to the strata temperature database. The quality and reliability of the data improved throughout time and ultimately led to the production of a geothermal catalogue, first published by Burley and Edmunds (1978) and subsequently updated by Burley and Edmunds (1984). Further data were added and are presented by Rollin et al. (1995). The catalogue (amongst other things) detailed heat flow and temperature measurements at discrete depths from various sources. These values allowed a model of estimated temperatures at various depths to be calculated and a heat flow map to be compiled. The catalogue currently holds the following data:

- A total of 878 boreholes have observed data at or below 500 m BSL. A total of 501 boreholes have observed data at or below 1000 m BSL. A total of 52 boreholes have observed data at or below 2000 m BSL. These observed data have been used to interpolate temperature. Overall it contains data from 567 boreholes that are >1000 m BSL.
- Subsurface temperature data are available for 1216 sites. From these sites 3057 temperature observations have been made, of which 2118 are Bottom Hole Temperatures (BHT).
- A total of 4694 thermal conductivity measurements were taken from 113 sites across the UK. These were measured from core samples and chippings.

There are 212 heat flow sites from which an estimated 6437 thermal conductivity measurements were taken. Figure 2-11 shows the estimated temperatures at 100 m, 200 m, 500 m and 1000 m across the UK whilst Figure 2-12 shows estimated heat flow across the UK (Busby et al., 2011).

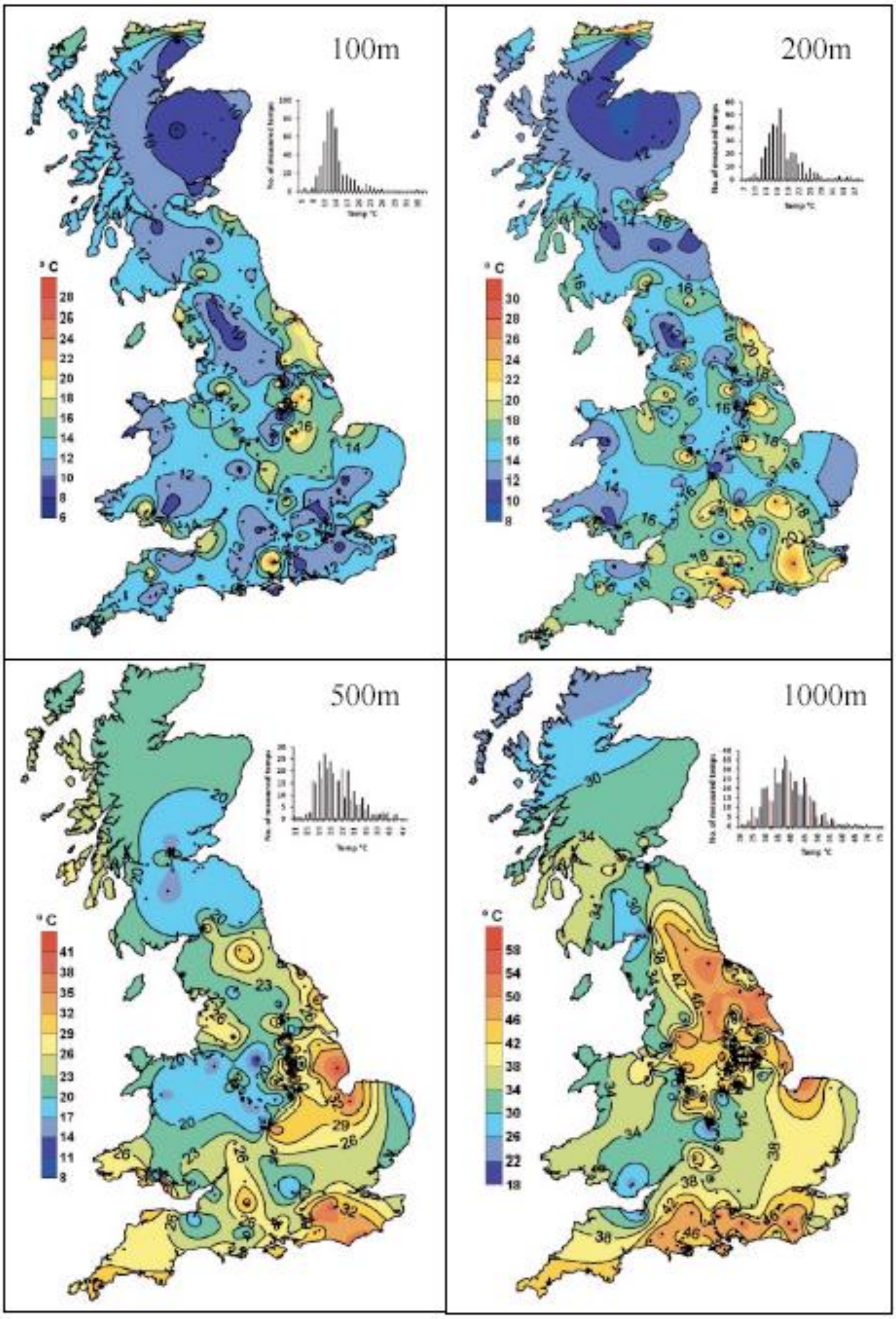


Figure 2-11 Estimated temperature at 100 m, 200 m, 500 m and 1000 m depth (Busby et al., 2011). It should be noted the kriging/contouring on these plots reflects data quantity; areas with little or no data are poorly constrained whilst areas with more data appear overly sensitive to kriging. It serves as a reminder of the difficulties faced by the geothermal industry in characterization of the UK geothermal gradient

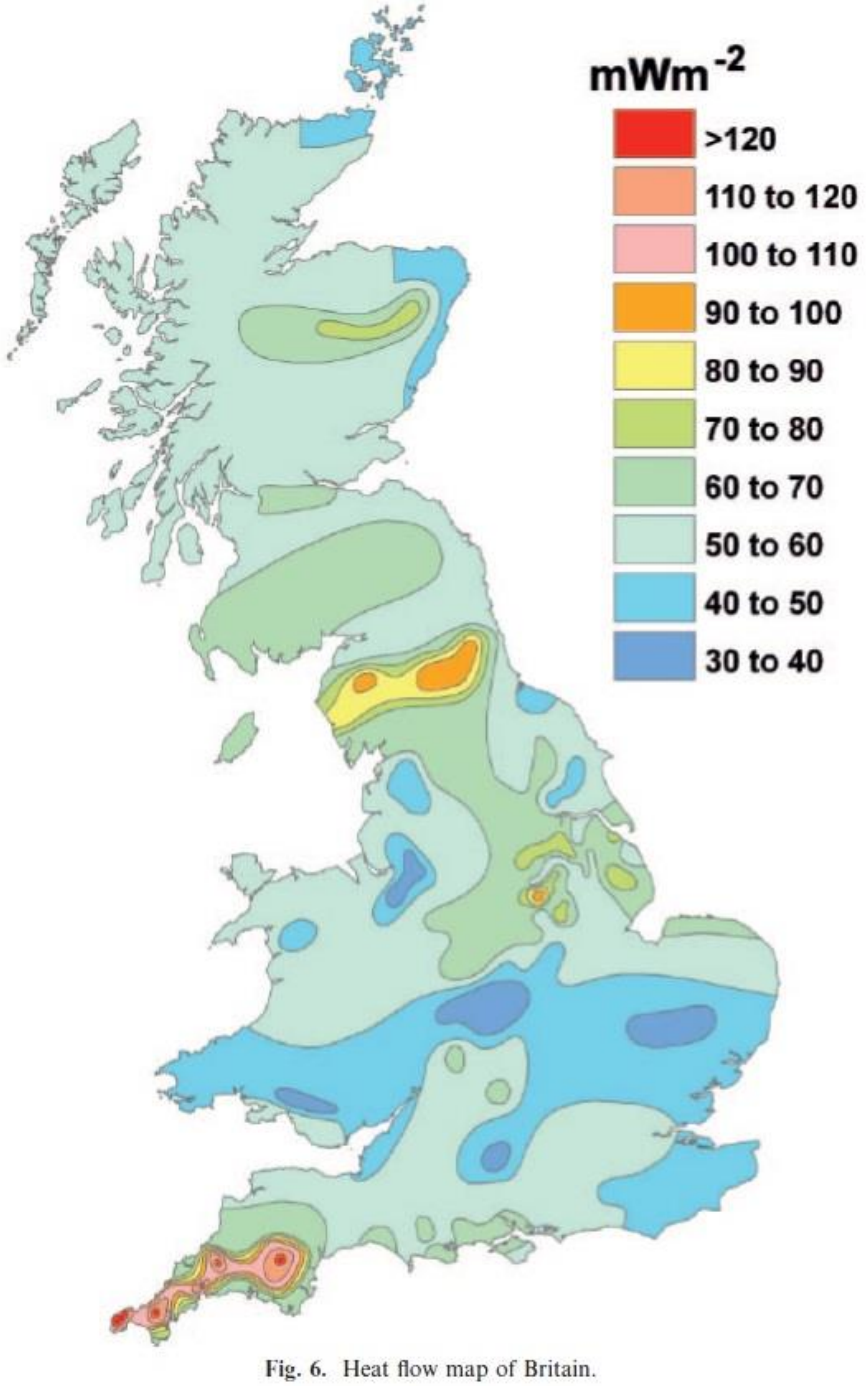


Figure 2-12: Heat flow map of the UK (Busby et al., 2011)

A total of six sedimentary basins were identified as having large accumulations of Permo-Triassic sediments that can be seen on Figure 2-13. These basins were identified as having the potential to contain water at 2 km depth at a temperature of 60°C. Using heat pumps these basins could form valuable direct use geothermal resources.

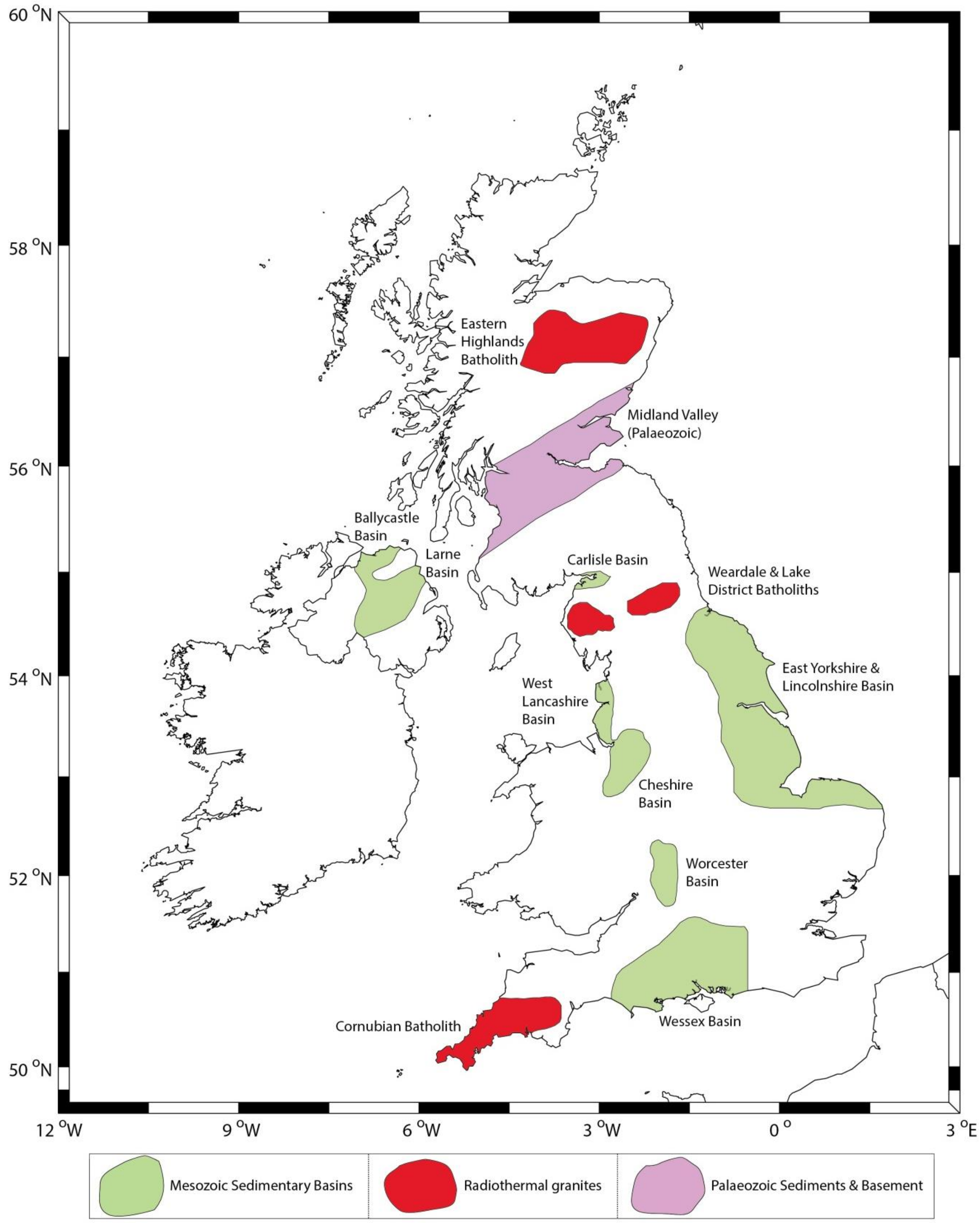


Figure 2-13: Location of Mesozoic Basins (Barker et al., 2000)

As part of this main phase of geothermal exploration a total of seven boreholes were drilled across the UK (Younger et al., 2012). Four of these boreholes specifically targeted low enthalpy Mesozoic basins whilst the remaining three investigated the high enthalpy resource associated with the Carnmenellis Granite, Rosemanowes, Cornwall. Table 2-3 displays BHTs that were recorded within these boreholes (Downing and Gray, 1986a).

Table 2-3: Summary of UK-specific borehole temperatures (Downing and Gray, 1986a)

Location	Completion Date	Depth (m)	Bottom Hole Temperature (°C)
Marchwood	1980	2609	88
Larne	1981	2873	91
Southampton	1981	1823	77
Cleethorpes	1984	2092	69
Rosemanowes RH11	1981	2175	90
Rosemanowes RH12	1981	2143	90
Rosemanowes RH15	1985	2652	100
Eastgate 1	2004	995	46
Eastgate 2	2010	420	-
Science Central	2011	1821	74

Modest temperature gradients were found with Southampton eventually exploiting waters of 76°C at a depth of approximately 1800 m (Manning et al., 2007; Younger et al., 2012). Enhanced Geothermal Systems (EGS, formally HDR), designed to utilise heat generated from radiothermal granites, were examined at Rosemanowes Quarry, Cornwall, but did not yield a working system in the UK. However, data obtained from these experiments were used to design the Soultz-sous-Forêts project (Rhine Graben).

The testing undertaken between 1976 and 1990 yielded important information regarding the UK's geothermal potential, and more importantly placed a value on the available resource. Resources located solely within deep Mesozoic sedimentary basins in the UK were estimated to be 300 EJ (Younger et al., 2012). To put some perspective on such a value it equates to enough heat "to decarbonise the UK heating requirement for the next 100 years" (Younger et al., 2012). The original investigation did not assess any potential associated with Palaeozoic-age sediments, the reasons for which are discussed within Chapter 4. A summary of general aquifer properties was presented by Holliday (1986) but no resource quantification was provided. The omission of Palaeozoic sediments is one that has been addressed by more recent work (see Section 2.3.2) and also within this thesis. The research undertaken within Chapter 4 and 5 is solely based on quantifying the geothermal reserve associated with fluid extraction from oil-bearing Carboniferous sediments underlying the East Midlands.

2.3.2 Recent UK Geothermal Exploration

Geothermal resources in the UK came back to the fore in 2004 with exploration opportunities arising at Eastgate, Co Durham and Science Central, Newcastle-Upon-Tyne, both funded in part by DECC. The resurgence has been attributed to increased climate change awareness; geothermal energy has one of the lowest carbon emission rates of all energy production technologies. In addition it provides a stable base load which is in contrast to wind and solar powered renewable energies (Younger et al., 2012), and in practical terms has a low spatial and visual impact. The two sites identified for their geothermal potential were drilled in 2004/2010 and 2011 respectively. The sites are located approximately 40 km apart (as shown on Figure 2-14), yet both target a resource that has a common origin.

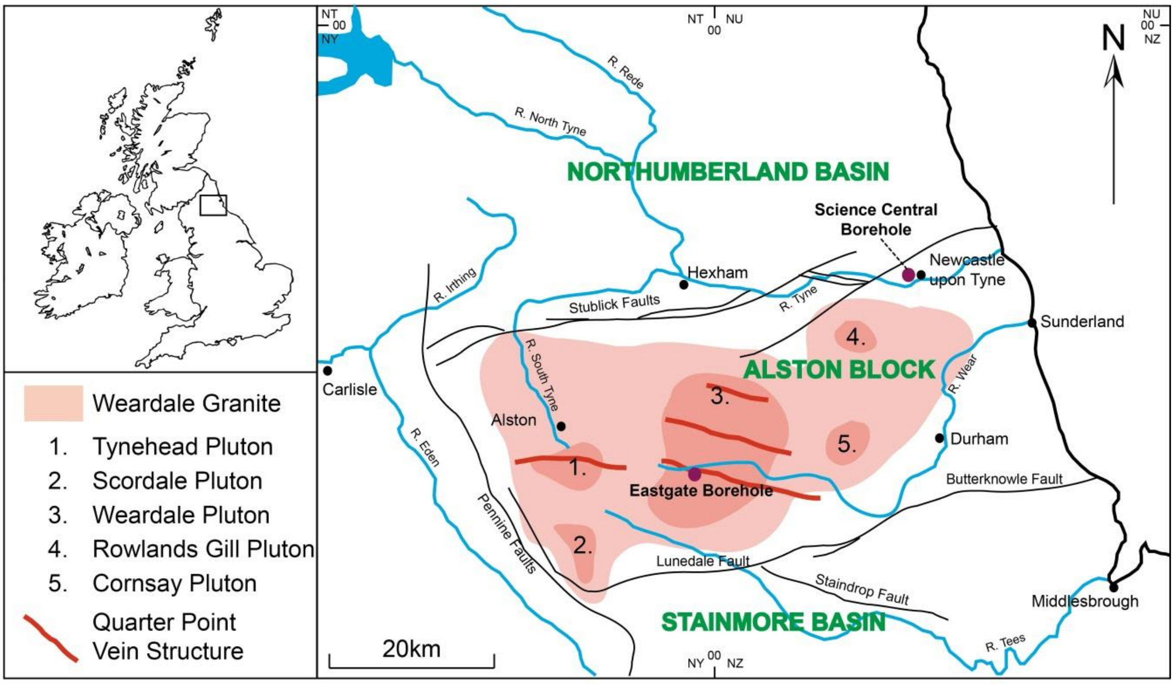


Figure 2-14: Map showing Eastgate borehole and Science Central borehole in relation to the main structural features of the Alston Block.

2.3.2.1 Eastgate

Eastgate signalled the beginning of a new phase of geothermal exploration within the UK. The borehole aimed to assess the geothermal potential associated with the Weardale Granite; a radiothermal granite that underlies the North Pennines/Alston Block of County Durham. Rather than explore the radiothermal aspect of the potential resource, the area was chosen given the likelihood of large natural fractures intersecting the granite. Hydraulic fracturing would not be required to create the transmissivity required making the Eastgate resource unique (Manning et al., 2007; Younger et al., 2015). The drill site was located at Eastgate within Weardale, Co Durham; an AONB, SSSI and Britain's first designated European and Global Geopark due to the high concentration of mineralisation occupying faults across the area. A large concentration of mines that were worked as far back as Roman times exploited the veins and exported lead and fluorspar in large quantities. Geothermal interest was piqued when observations of warm water issuing from

Cambokeels Mine at Eastgate was noted during the 1980's. The mine exploited the Slitt Vein; an ESE/E-W trending vein yielding high concentrations of lead and fluorspar. Further analysis of water samples was undertaken by Manning and Strutt (1990). The conclusions reached were as follows:

- The groundwater is derived from a deep source, forming ultimately from organic rich sedimentary rocks.
- Low concentrations of K, Na and Li indicated the groundwater had at some point interacted with the Weardale Granite and there must be reasonable permeability within the vein to allow up-flow to the mine levels.

Based on the above it was anticipated that warm groundwater was still circulating at depth within the Slitt Vein. The enhanced permeability found linked with a granite formed the basis of a new exploratory phase of investigation that had previously never been assessed in the UK. Rather than design an EGS system reliant on the radiothermal heat producing capacity of the granite, the sinking of the UK's first geothermal borehole in approximately 20 years specifically targeted the natural permeability of the Slitt Vein, and therefore that of the Weardale Granite (Younger et al., 2012). The borehole, located on the former Blue Circle Cement works site in Eastgate, was to form part of the regeneration scheme planned for the site. The borehole was completed in December 2004 terminating at 995 m below ground level with a geothermal gradient of 3.8°C per 100 m and BHTs of 46°C (Manning et al., 2007). Transmissivity values in excess of 4000 D m and favourable hydraulic test results indicated the granite had a permeability that had not been seen anywhere else in the world to date (Younger and Manning, 2010). Large sub-vertical open fractures oblique to the borehole were also discovered which appeared to persist over large lateral distances and displayed similarly large transmissivity values. The discovery of circulating saline brines emanating at ground level led to the Slitt Vein being characterised as a relatively permeable conduit through which deep seated fluids could circulate. Temperature gradients from the Rookhope borehole of 3.0°C per 100 m (Downing and Gray, 1986a), and 6.0°C per 100 m at Frazer's Grove Mine (Younger, 2000) suggested similar characteristics could possibly be in existence at these locations.

The site remains a development opportunity with planning permission, considering the following factors:

- Site ownership and funding to develop an eco-village. Plans were produced to make the site a tourist attraction whereby the heat extracted from the water would be used to heat a spa and a range of other developments.
- The resource in its current capacity would be used for heating only, not electricity. If the well was deepened and transmissivity was found to be good, an existing 33 kV tie is located on the site. However, to deepen the well further exploration would be required.
- Location – it is a rural community and heat demand is low. Transporting heat over any sort of distance results in expensive infrastructure and temperature losses that may render the scheme un-economic.

The site was sold in March-April 2015 but the buyer of the land is currently not disclosed. It is not widely known what future the site holds from a geothermal perspective.

2.3.2.2 Science Central, Newcastle-Upon-Tyne

A second phase of geothermal exploration began in 2010 when funding was granted to the Science City Partnership for a geothermal borehole located in Newcastle-Upon-Tyne. The city of Newcastle has been designated as one of six “Science Cities”, recognising the world class research being undertaken at the University. One of the key priorities was sustainability and as such the idea of a geothermal borehole covering some (if not all) of the heat demand required by developments / businesses in the area was one that was met very positively. The borehole was located on the former Newcastle Brewery Site such that it could test the Stublick-90 Fathom Fault; a pervasive east-west trending fault that marks the northern boundary of the Alston Block (located on Figure 2-14), and is likely an extensional reactivation of an Iapetus-aged suture marking the meeting of two continents during the Caledonian Orogeny. It is also likely in hydraulic connectivity with the Weardale Granite underlying the Northern Pennine Orefield to the west (Younger et al., 2015). Evidence to support a potential geothermal resource underlying Newcastle Upon Tyne are described below (Younger et al., 2015).

1. Zonation of coal rank within the Great Northern Coalfield indicates higher than average heat flows have existed.
2. Cementation of Basal Permian Sands at Cullercoats by barite indicate permeable zones and channelized fluid flow along the fault plane.
3. Recent hydrothermal circulation in coal mines; both Rising Sun and Backworth Collieries noted BaCl brines rising up through footwall and main fault splays.

Equilibration temperatures of 150-200°C were recorded, similar to those seen at Eastgate. These are located on North Tyneside.

4. BaCl springs are noted across the northeast. Anderson (1945) presents water chemistry data from coal mines across the northeast. Many of these waters are chloride rich, and in some cases are BaCl-enriched, hinting at large scale fluid circulation.

The exploration rationale behind the siting of the Science Central borehole was based firstly on the likelihood that fault splays associated with the Stublick-90 Fathom Fault system would most likely provide connectivity with the heat-producing Weardale Granite. These splays were inferred from seismic profile lines and would likely be intersected at 500-1800 m below ground level. The potential for groundwater temperatures to be ≥70°C was deemed likely given the known geothermal gradient associated with Eastgate. Lastly the potential for permeable formations at depth was also deemed likely, as the Carboniferous Fell Sandstone Formation was likely to occupy the interval around 1500-1800 m below ground level. The permeability of the Fell Sandstone can be good enough to allow it to be used as a potable water supply, and indeed it is used for this purpose in Northumberland. It was noted that the Fell Sandstone has a coarse grain size where it intersects W-E faults that were active during deposition (Younger et al., 2015).

Drilling was completed in 2011 and terminated at 1,821 m within the Carboniferous Ballagan Group of the Inverclyde Formation. Approximately 300 m of Fell Sandstone was proved within the borehole. A BHT of 73°C was measured at 1,772 m, with a temperature gradient of 3.7°C per 100 m (Younger et al., 2015). Further plans to drill daughter wells that would be angled such that they could intersect fault-permeable zones would have been the next step, however, issues with the original well and lack of funding meant these were never drilled. Currently the condition of the well has not permitted abstraction of water in economic quantities as the permeability is not sufficient within this section of the Fell Sandstone; the well is likely to be used for other purposes at this stage.

2.3.3 The Future of UK Geothermal Exploration

To date a total of 10 geothermal-specific boreholes have been drilled across the UK between 1977 and 2011 to further aid our understanding of geothermal resource quantity and distribution. Whilst the initial focus was on sedimentary basins of Permo-Triassic age and radiothermal granites, more recent projects have started looking at previously unquantified resources. Palaeozoic sediments, or more specifically Carboniferous and

Devonian sediments, have been largely ignored in resource quantification to date. The more recent sinking of Eastgate and Science Central bores have both targeted resources that that fall within this age bracket and only adds to the overall quantification of the UK low enthalpy resource base. There are several other projects for which research is currently ongoing at the time of writing, summarised by Younger et al. (2015).

1. Scotland
    a. A re-evaluation of radiothermal granites is an ongoing project.
    b. A project assessing the potential associated with Devonian and Carboniferous sediments within the Midland Valley is currently being undertaken. Existing borehole data has been re-processed and corrections applied (Westaway and Younger, 2013). Based on corrected heat flow, temperatures are predicted to be 70-80°C at 2-3 km.
    c. A desk study report produced by AECOM (AECOM, 2013) for the Scottish Government has been produced to determine the impact exploitation of Scottish geothermal reserves could have on renewable targets. A particular feature was the inclusion of using heat pumps in old flooded mine workings.
2. Northeast England
    a. Auckland Castle Geothermal Project, Bishop Auckland. A project to supply heat from a deep geothermal borehole is being assessed at Auckland Castle in County Durham. The borehole aims to target a similar E-W trending fault structure (the Butterknowle Fault) to that seen at Science Central (the Stublick-90 Fathom Fault), with target rocks being Carboniferous in age (Younger et al., 2015).
3. Mesozoic Basins – The Cheshire Basin
    a. The focus on a sedimentary basin of Mesozoic age harks back to the original phase of geothermal exploration. Two local authorities (Stoke-On-Trent and East Cheshire) are both looking to develop a deep borehole exploiting the likelihood of warm (80°C) water at 2-3 km depth for use in district heating networks.

The current work described above indicates there is still scope for further exploration and quantification of low enthalpy resources. Previously uncharacterised and unquantified strata exist that fall outside the original geothermal exploration remit; several projects are beginning the address this gap in knowledge.

2.4 References

AECOM, 2013, Study into the Potential for Deep Geothermal Energy in Scotland, The Scottish Government.

AGRCC-Australian Geothermal Reporting Code Committee, 2010a, Geothermal Lexicon for Resources and Reserves Definition and Reporting (Edition 2).

-, 2010b, The Geothermal Reporting Code, Second Edition.

Anderson, W., 1945, On the Chloride Waters of Great Britain: Geological Magazine, v. 82, no. 06, p. 267-273.

Andrews-Speed, C. P., Oxburgh, E. R., and Cooper, B. A., 1984, Temperatures and depth-dependant heat flow in western North Sea: The American Association of Petroleum Geologists, v. 68, no. 11, p. 1764-1781.

Anzellini, S., Dewaele, A., Mezouar, M., Loubeyre, P., and Morard, G., 2013, Melting of Iron at Earth's Inner Core Boundary Based on Fast X-ray Diffraction: Science, v. 340, no. 6131, p. 464-466.

Banks, D., 2008, An Introduction to Thermogeology: Ground Source Heating and Cooling, Newcastle-Upon-Tyne: Blackwell Publishing.

Barker, J. A., Downing, R. A., Gray, D. A., Findlay, J., Kellaway, G. A., Parker, R. H., and Rollin, K. E., 2000, Hydrogeothermal studies in the United Kingdom: Quarterly Journal of Engineering Geology and Hydrogeology, v. 33, no. 1, p. 41-58.

Ben Dhia, H., 1988, Tunisian geothermal data from oil wells: Geophysics, v. 53, no. 11, p. 1479-1487.

Bloomer, J. R., Richardson, S. W., and Oxburgh, E. R., 1979, Heat Flow in Britain: an Assessment of the Values and Their Reliability, *in* Čermák, V., and Rybach, L., eds., Terrestrial Heat Flow in Europe, Springer Berlin Heidelberg, p. 293-300.

British Geological Survey, 2016, Earthquakes in the UK, http://bgs.ac.uk/discoveringGeology/hazards/earthquakes/UK.html.

Bullard, E. C., 1947, The time necessary for a bore hole to attain temperature equilibrium Geophysical Journal International, v. 5, p. 127-130.

Burley, A. J., and Edmunds, W. M., 1978, Catalogue of geothermal data for the land area of the United Kingdom: British Geological Survey.

-, 1984, Catalogue of geothermal data for the land area of the United Kingdom: Investigation of the Geothermal Potential of the UK (second revision). Department of Energy, p. 26.

Busby, J., 2014, Geothermal energy in sedimentary basins in the UK: Hydrogeology Journal, v. 22, no. 1, p. 129-141.

Busby, J., Kingdon, A., and Williams, J., 2011, The measured shallow temperature field in Britain: Quarterly Journal of Engineering Geology and Hydrogeology, v. 44, no. 3, p. 373-387.

Clark, C. D., Hughes, A. L. C., Greenwood, S. L., Jordan, C., and Sejrup, H. P., 2012, Pattern and timing of retreat of the last British-Irish Ice Sheet: Quaternary Science Reviews, v. 44, p. 112-146.

Davies, J. H., 2013, Global map of solid Earth surface heat flow: Geochemistry, Geophysics, Geosystems, v. 14, no. 10, p. 4608-4622.

Davies, J. H., and Davies, D. R., 2010, Earth's surface heat flux: Solid Earth, v. 1, no. 1, p. 5.

Deming, D., 1989, Application of bottom-hole temperature corrections in geothermal studies: Geothermics, v. 18, no. 5–6, p. 775-786.

Downing, R. A., and Gray, D. A., 1986a, Geothermal Energy: The potential in the United Kingdom London, HMSO.

-, 1986b, Geothermal resources of the United Kingdom: Journal of the Geological Society, v. 143, no. 3, p. 499-507.

Falcone, G., and Beardsmore, G., 2015, Including Geothermal Energy within a Consistent Framework Classification for Renewable and Non-Renewable Energy Resources: Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Falcone, G., Gnoni, A., Harrison, B., and Alimonti, C., 2013, Classification and Reporting Requirements for Geothermal Resources, European Geothermal Congress, Pisa, Italy, 2013

Förster, A., 2001, Analysis of borehole temperature data in the Northeast German Basin: continuous logs versus bottom-hole temperatures: Petroleum Geoscience, v. 7, no. 3, p. 241-254.

Förster, A., and Merriam, D., 1995, A bottom-hole temperature analysis in the American Midcontinent (Kansas): implications to the applicability of BHTs in geothermal studies, International Geothermal Association, Proceedings of the World Geothermal Congress, Florence, Italy, Volume 2, p. 777-782.

Holliday, D. W., 1986, Devonian and Carboniferous Basins, *in* Downing, R. A., and Gray, D. A., eds., Geothermal Energy: The Potential in the United Kingdom: London, HMSO, p. 27.

Huenges, E., 2010, Geothermal Energy Systems: Exploration, Development and Utilization, WILEY-VCH Verlag GmbH & Co. KGaA.

Jaupart, C., Labrosse, S., and Mareschal, J. C., 2007, 7.06 - Temperatures, Heat and Energy in the Mantle of the Earth, *in* Schubert, G., ed., Treatise on Geophysics: Amsterdam, Elsevier, p. 253-303.

Kappelmeyer, O., 1979, Implications of heat flow studies for geothermal energy prospects., *in* Cermak, V., and Rybach, L. O., eds., Terrestrial Heat Flow in Europe, Springer-Verlag, Berlin, p. 126-135.

KIC InnoEnergy, 2016: EIT Knowledge & Innovation Community, http://www.kic-innoenergy.com/.

Lee, J. R., 2011, Cool Britannia: from Milankovitch wobbles to ice ages: Mercian Geologist, v. 17, no. 4, p. 274-279.

Lund, J. W., 2006, Chena Hot Springs, Geo-Heat Center Quarterly Bulletin, Volume 27: Klamath Falls, Oregon, p. 2-4.

-, 2007, Characteristics, development and utilization of geothermal resources: Geo-Heat Center Quarterly Bulletin, v. 28, no. 2, p. 1-9.

Manning, D. A. C., and Strutt, D. W., 1990, Metallogenetic Significance of a North Pennine Springwater: Mineralogical Magazine, v. 54, p. 629-636.

Manning, D. A. C., Younger, P. L., Smith, F. W., Jones, J. M., Dufton, D. J., and Diskin, S., 2007, A deep geothermal exploration well at Eastgate, Weardale, UK: a novel exploration concept for low-enthalpy resources: Journal of the Geological Society, v. 164, no. 2, p. 371-382.

Moeck, I. S., 2014, Catalog of geothermal play types based on geologic controls: Renewable and Sustainable Energy Reviews, v. 37, p. 867-882.

Muffler, P., and Cataldi, R., 1978, Methods for regional assessment of geothermal resources: Geothermics, v. 7, no. 2, p. 53-89.

Oxburgh, E. R., Richardson, S. W., Turcotte, D. L., and Hsui, A., 1972, Equilibrium bore hole temperatures from observation of thermal transients during drilling: Earth and Planetary Science Letters, v. 14, no. 1, p. 47-49.

Prensky, S., 1992, Temperature Measurements in Boreholes - An Overview of Engineering and Scientific Applications: The Log Analyst, v. 33, no. 3, p. 313-333.

Richardson, S. W., and Oxburgh, E. R., 1978, Heat flow, radiogenic heat production and crustal temperatures in England and Wales: Journal of the Geological Society, v. 135, no. 3, p. 323-337.

Rollin, K. E., 1995, A simple heat-flow quality function and appraisal of heat-flow measurements and heat-flow estimates from the UK Geothermal Catalogue: Tectonophysics, v. 244, no. 1–3, p. 185-196.

Rollin, K. E., Kirby, G. A., Rowley, W. J., and Buckley, D. K., 1995, Atlas of Geothermal Resources in Europe: UK Revision: British Geological Survey, Regional Geophysics Series, Technical Report WK/95/07.

Rybach, L., 2010, The Future of Geothermal Energy and its Challenges, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.

Sanyal, S. K., 2005, Classification of Geothermal Systems - A Possible Scheme, Thirtieth Workshop on Geothermal Reservoir Engineering: Stanford University, Stanford, California, p. 85-88.

Selley, R. C., and Sonnenberg, S. A., 2015, Elements of Petroleum Geology (Third Edition), Elsevier.

Tryggvadottir, L., 2013, Geothermal Reporting Code Review: European Geothermal Energy Council (GeoElec).

Waples, D. W., Pacheco, J., and Vera, A., 2004, A method for correcting log-derived temperatures in deep wells, calibrated in the Gulf of Mexico: Petroleum Geoscience, v. 10, no. 3, p. 239-245.

Waples, D. W., and Ramly, M., 2001, A statistical method for correcting log-derived temperatures: Petroleum Geoscience, v. 7, no. 3, p. 231-240.

Westaway, R., and Younger, P. L., 2013, Accounting for palaeoclimate and topography: A rigorous approach to correction of the British geothermal dataset: Geothermics, v. 48, no. 0, p. 31-51.

Wheildon, J., and Rollin, K. E., 1986, Heat Flow, *in* Downing, R. A., and Gray, D. A., eds., Geothermal Energy: The potential in the United Kingdom: London, HMSO, p. 13.

Williams, C. F., Reed, M. J., and Anderson, A. F., 2011, Updating the Classification of Geothermal Resources, Proceedings: Thirty-Sixth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California.

Younger, P. L., 2000, Nature and practical implications of heterogeneities in the geochemistry of zinc-rich, alkaline mine waters in an underground F–Pb mine in the UK: Applied Geochemistry, v. 15, no. 9, p. 1383-1397.

Younger, P. L., Feliks, M. E. J., Westaway, R., McCay, A. T., Harley, T. L., Elliott, T., Stove, G. D. C., Ellis, J., Watston, S., and Waring, A. J., 2015, Renewing the Exploration Approach for Mid-Enthalpy Geothermal Systems: Examples from Northern England and Scotland, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April, 2015.

Younger, P. L., Gluyas, J. G., and Stephens, W. E., 2012, Development of deep geothermal energy resources in the UK: Proceedings of the Institution of Civil Engineers - Energy, v. 165, no. 1, p. 19-32.

Younger, P. L., and Manning, D. A. C., 2010, Hyper-permeable granite: lessons from test-pumping in the Eastgate Geothermal Borehole, Weardale, UK: Quarterly Journal of Engineering Geology and Hydrogeology, v. 43, no. 1, p. 5-10.

Chapter 3:

Geothermal Energy Systems of the UK and neighbouring European Countries: A comparison of resources, their exploitation and barriers to their development

3.1 Executive Summary

The exploitation of geothermal resources within the UK is small when compared with other countries that hold similar resources. The resource base, however, does exist; 300 EJ exist in Mesozoic basins alone – enough to decarbonise the UK heating requirements for the next 100 years (Younger et al., 2012). The UK, Denmark, the Netherlands, Germany and France all have deep geothermal reservoirs that formed contemporaneously having developed as part of two large scale basins (the Anglo-Paris Basin and the Northwest European Basin), but have been exploited to varying magnitudes. Therefore, barriers to the development of these resources must exist. These can be both technical (geological, mechanical) and non-technical (social, political, economic). Technical barriers are those that affect the physical parameters of the resource and extracted fluids. Ultimately technical barriers can be overcome through careful planning and strong financial backing; obtaining sufficient flow rates can be achieved even if natural permeability does not exist through thermal fracturing hydraulic modification of the target formation. Identified technical barriers affect all the assessed countries to a similar magnitude and it is not thought they have caused the variation in resource development. The barriers that currently hinder the development of UK resources are dominantly non-technical in nature. They fall into two groups: policy-based barriers (Government policy, licensing policy) and risk-based (risk insurance) barriers. These are intrinsically linked, each feeding into the other. All countries assessed suffer to a degree from these barriers but the UK appears to be hindered the most. It is my view that lack of a risk insurance scheme and Government support are the dominating reasons why UK deep geothermal currently lags behind that seen in Denmark, France, Germany and the Netherlands. There is wider issue beyond these barriers, however. The over-riding issue with UK development of geothermal energy is the legacy of decisions made 30-40 years ago. Our recent development as a nation was dependent on North Sea petroleum and the infrastructure and policy that has grown out of this industry means we are some years behind other countries. Comparative countries all had a similar energy mix in 1970 (>90% of energy came from fossil fuel based sources), and all apart from Denmark continued large scale use of North Sea gas. However, policy was not solely developed around renewables and gas; there were efforts to focus on energy efficiency, infrastructure, building regulation and district heating. The UK Government last assessed deep geothermal resources in 2013 (Atkins, 2013) but chose to focus on delivering power rather than heat, something that was regarded as short-sighted by the industry in a country dominated by low-enthalpy deep geothermal resources.

3.2 Introduction

As discussed in Chapter 2 the UK geothermal resource base has been estimated to be 300 EJ (Busby, 2010) which could contribute towards off-setting the UK's annual heating "bill"; almost 50% of total energy consumption within the UK is used for heating purposes (DECC, 2012). Utilising geothermal resources are advantageous for the following reasons:

- Low greenhouse gas emitters: Direct-use geothermal systems, once operational, produce negligible CO_2 noted to be <1 g CO_2/kWh_{th}. It can be also be argued that these emitted gases cannot be classed as emissions as they are in fact naturally occurring CO_2 fluxes that would be vented to the atmosphere irrespective of the geothermal system in operation (Goldstein et al., 2011). For comparison offshore wind produces 12 g CO_2/kWh (Thomson and Harrison, 2015).
- The resource is non-intermittent. The systems can produce a steady output of heat over a period of decades before resting is required (the International Energy Agency (2011b) uses a 27 year lifespan in their calculations), but will ultimately recover to continue producing power and/or heat.
- The surface infrastructure occupies a small surface area. The Southampton District Heating well bore occupies an area of 46 m^2 (four car park spaces) making the system easy to fit into existing built-up areas.

Deep low-enthalpy geothermal is defined as being >300 m depth (International Energy Agency, 2010). The benefit of utilising such a resource has been recognised by countries around the world, many of which are located in tectonically quiescent settings not dissimilar to that seen in the UK. However, the level of uptake across these countries is variable hinting at potential limitations and barriers that are not solely related to tectonic setting. For UK resources, understanding the nature of these barriers is important if we are to build upon the only deep geothermal system currently installed in the country (Southampton).

3.2.1 Energy Density

The exploitation of geothermal resources for heat-only projects are at an immediate disadvantage due to the energy density of geothermal fluids; one barrel of geothermally produced hot water does not have the same energy density or value as a barrel of crude oil. One US barrel of crude oil contains 6.1×10^6 kJ (EIA, 2015). A US barrel of hot saline water with a temperature of 60°C, specific heat capacity of 3.93 kJ kg^{-1} K and density of 1023 kg m^{-3} has an extractable heat energy of $3.8x10^4$ kJ. The estimate assumes the heat within the water is fully depleted from 60°C to 0°C. Difference in energy density makes it difficult to attract investment, and the payback time is less than a hydrocarbon-derived fuel (although the payback time is purported to be competitive with conventional energy systems – International Energy Agency, 2010). However, as discussed above geothermal systems are not high polluting industries and the associated cost of cleaning up such systems is minimal when compared to other technologies. It also does not attract emissions-based taxes given the low emissions direct-use geothermal systems produce. This provides some balance to counter the lower energy density contained within geothermal fluids.

The competitiveness of geothermal resource exploitation when compared to other heat-specific renewable energy sources has been assessed by comparing capital costs and the Levelised Cost of Energy (LCOE), as presented in Figure 3-1 and 3-2 (REN 21, 2015). Capital costs for geothermal district heating indicate that geothermal space heating systems are at the upper limit of investment whilst district heating is on a par with other technologies. The LCOE displayed in Figure 3-2 indicates a similar trend.

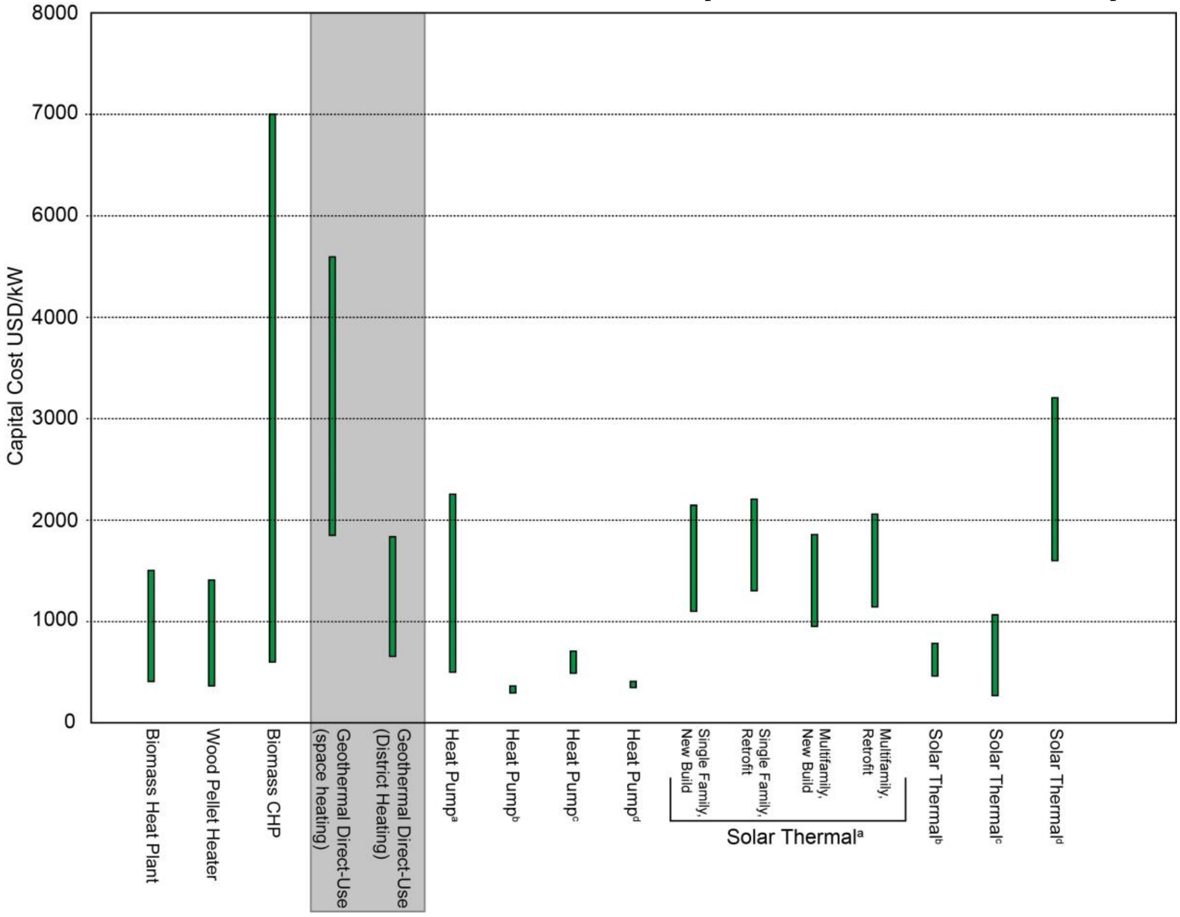


Figure 3-1: Capital costs (USD/kW) of renewable technologies used for hot water / heating and cooling purposes (REN 21, 2015). Heat Pump[a] – ground source, residential & commercial; Heat Pump[b] – domestic water heaters; Heat Pump[c] – water source, residential including multifamily; Heat Pump[d] – air source; Solar Thermal[a] - domestic hot water systems; Solar Thermal[b] – domestic heat and hot water combi-systems; Solar Thermal[c] – industrial process heat; Solar thermal[d] – cooling.

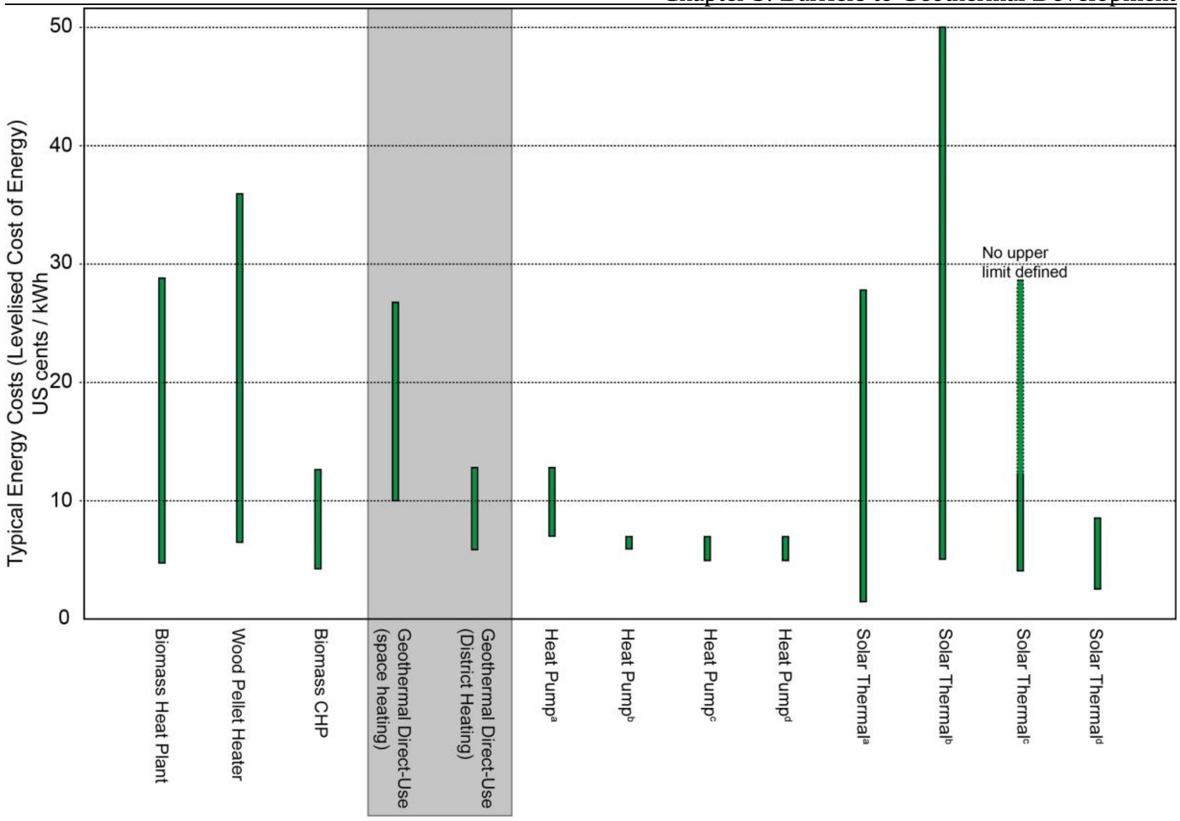


Figure 3-2: Levelised Cost of Energy (US cents/kWh) for renewable technologies used for hot water / heating and cooling purposes (REN 21, 2015). Heat Pump[a] – ground source, residential & commercial; Heat Pump[b] – domestic water heaters; Heat Pump[c] – water source, residential including multifamily; Heat Pump[d] – air source; Solar Thermal[a] – domestic hot water systems; Solar Thermal[b] – domestic heat & hot water combi-systems, domestic hot water; Solar Thermal[c] – domestic heat & hot water combi-systems, district heat; Solar Thermal[d] – industrial process heat, Europe.

Geothermal can be seen as a competitive technology when considered alongside other heat-specific renewable technologies.

3.2.2 Installed Geothermal Capacity

A review of worldwide installed geothermal capacity has been summarised separately by Lund and Boyd (2015) and Bertani (2015). The former presents data regarding direct-use geothermal systems, whilst the latter presents data from indirect-use (electrical capacity) systems. It is important to make this distinction given the style of geothermal resource being investigated in the UK. Bertani (2015) stated that as of end-2015, the worldwide installed capacity for electrical power production using geothermal resources is 12,635 MW_e. The energy produced from this totalled 73,549 GWh. In comparison Lund and Boyd (2015) discuss and summarise the installed thermal capacity of geothermal heating systems across the world. As of end-2014, installed thermal capacity totalled 70,239 MW_t, producing 163,287 GWh energy. The installed thermal capacity value includes heat generated from ground source heat pumps which has seen a major increase over the period 2010-2015, demonstrated by Figure 3-3 and 3-4.

Figure 3-3 shows the installed direct-use geothermal capacity up to end-2012, whilst Figure 3-4 displays the same data but up to end-2015. The area displayed was chosen not only because the UK is represented (the focus of this study), but also because a wide range of tectonic settings are located within this geographic area and it makes for a useful comparison.

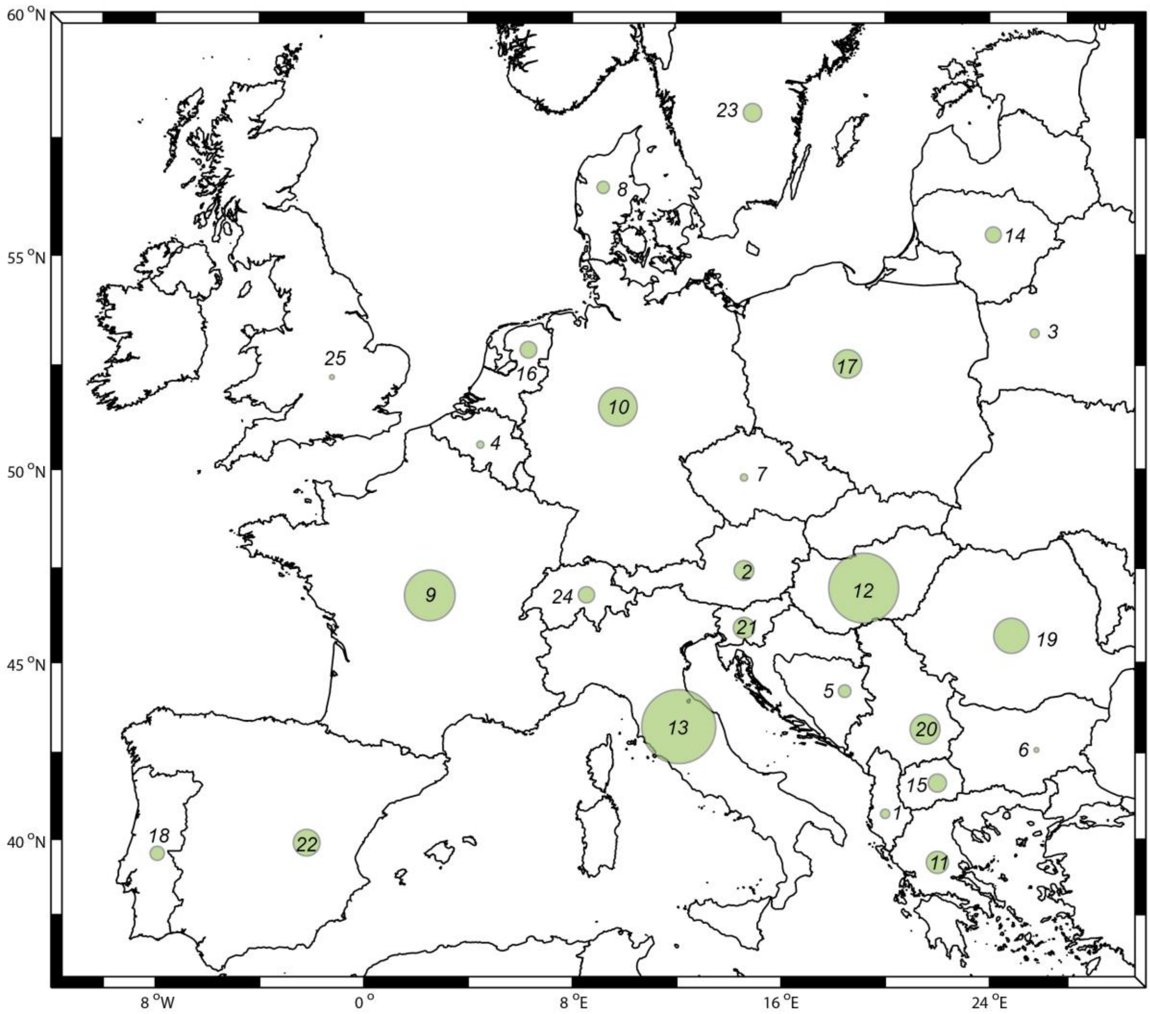


Figure 3-3: Country by country installed capacity for direct use geothermal energy (MW_t) for Europe, parts of Asia and parts of Africa as of end-2012. The size of the circle is proportional to the installed geothermal capacity, whereas the actual value can be found in this figure caption. This includes geothermal district heating. Data for countries *1-22* and *24-25* are taken from Antics et al. (2013). Data for *22* taken from IEA (2010). *1* – Albania (12 MW_t), *2* – Austria (55), *3* – Belarus (11), *4* – Belgium (7), *5* – Bosnia & Herzegovina (22),*6* – Bulgaria (3), *7* – Czech Republic (7), *8* – Denmark (21), *9* – France (365), *10* – Germany (211), *11* – Greece (69), *12* – Hungary (695), *13* – Italy (779), *14* – Lithuania (35), *15* – Macedonia (46), *16* – Netherlands (39), *17* – Poland (115), *18* – Portugal (28), *19* – Romania (176), *20* – Serbia (126), *21* – Slovenia (63), *22* – Spain (100), *23* – Sweden (48), *24* – Switzerland (37), *25* – UK (3).

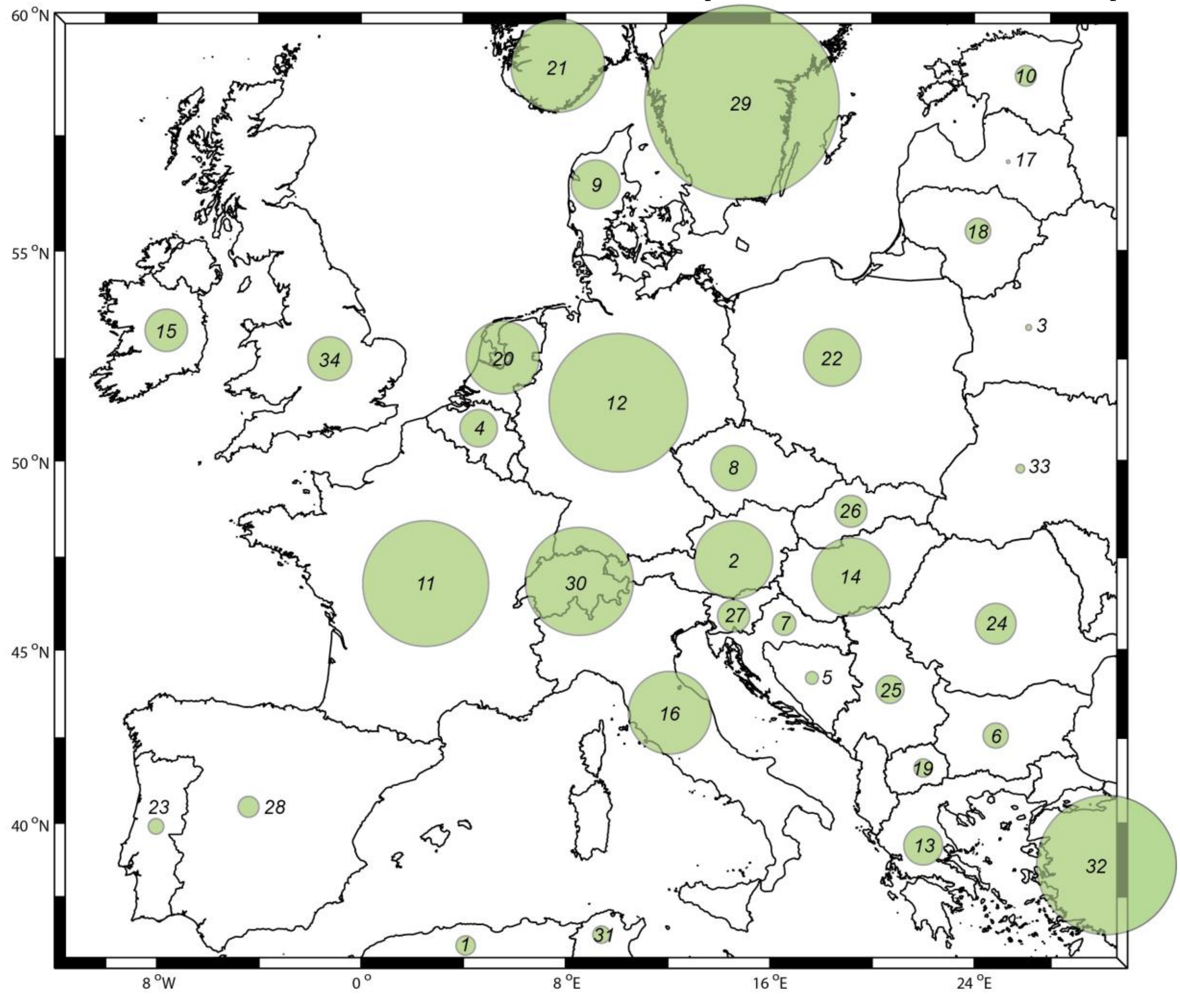


Figure 3-4: Country by country installed capacity for direct use geothermal energy (MW_t) for Europe, parts of Asia and parts of Africa as of end-2015. The size of the circle is proportional to the installed geothermal capacity, whereas the actual value can be found in this figure caption. This includes geothermal district heating. Data taken from Lund and Boyd (2015). *1* – Algeria (54.64 MW_t), *2* – Austria (903.4), *3* – Belarus (4.73), *4* – Belgium (206.08), *5* – Bosnia & Herzegovina (23.92), *6* – Bulgaria (93.11), *7* – Croatia (79.94), *8* – Czech Republic (304.5), *9* – Denmark (353), *10* – Estonia (63), *11* – France (2346.9), *12* – Germany (2848.6), *13* – Greece (221.88), *14* – Hungary (905.58), *15* – Ireland (265.54), *16* – Italy (1014), *17* – Latvia (1.63), *18* – Lithuania (94.6), *19* – Macedonia (48.68), *20* – Netherlands (790), *21* – Norway (1300), *22* – Poland (488.84), *23* – Portugal (35.2), *24* – Romania (245.13), *25* – Serbia (115.64), *26* – Slovakia (149.4), *27* – Slovenia (152.75), *28* – Spain (64.13), *29* – Sweden (5600), *30* – Switzerland (1733.08), *31* – Tunisia (43.8), *32* – Turkey (2886.3), *33* – Ukraine (10.9), *34* – United Kingdom (283.76).

The incorporation of shallow ground source heat pump data into the geothermal installed capacity dataset does not allow an assessment of the heat derived from deep geothermal systems only. The remit of this project (described in Chapter 1) is to assess the low enthalpy resource associated with deep sedimentary systems. Data presented on Figure 3-4 are also somewhat skewed by the addition of heat produced by shallow ground source heat pumps. As an example, the singular operational deep geothermal well in the UK produces 2 MW_t (Geothermal District Heating (GEODH), 2016); no other deep geothermal systems in the UK are exploited. The reported value of 283.76 MW_t by Lund and Boyd (2015) is, therefore, predominantly heat produced from shallow ground source geothermal settings.

Obtaining current values of installed deep geothermal capacity are difficult to obtain as these data are often not available. Regardless of this it can be seen that geothermal within the region displayed contains a lot of variation.

From the data presented within Section 3.2 it can be seen that deep low-enthalpy geothermal resources can be a viable technology to invest in. Despite the disparity in energy density (especially when compared to traditional non-renewable technologies), there are benefits to investing in low-enthalpy geothermal resource development. Barriers to the development of geothermal resources have been touched upon in Chapter 2. Barriers were focused upon the technical reporting of a resource where confusion could arise if the method by which a resource had been classified was not made clear. Applying inappropriate classification systems by those not skilled in geothermal resource assessment could lead to over-estimation of resources, which, when subsequent attempts at exploiting the resource are made, the scheme proves a failure. The application of inappropriate classification systems can introduce mistrust in geothermal resource exploitation and push it down the list of technologies that could be utilised to produce renewable energy.

The barriers described above are generalised to resource development around the World; they can indiscriminately affect any country. Given the low levels of uptake within the UK when compared to countries in similar tectonic settings (Figure 3-3 and 3-4) it is hypothesised additional barriers exist.

3.3 Aims & Objectives

Geothermal exploitation is not evenly distributed around the world. The uneven distribution is in the first instance caused by variation in heat flow as discussed in Chapter 2. However, further limitations and barriers to geothermal resource uptake also exist; it is these additional barriers / limiting factors that this Chapter will explore with respect to UK geothermal resource exploitation. The UK resource base has been compared with Germany, Denmark, the Netherlands and France as these countries are connected geologically to the UK via intercratonic basins and, therefore, are underlain by comparative geological successions. These countries all exploit deep low-enthalpy sedimentary aquifers to varying degrees highlighted by the installed capacity values presented in Figure 3-4. The following key objectives have been addressed:

- Obtain figures for global and EU scale geothermal resource installed capacity to place the UK in context within these areas. These figures will include installed electrical and thermal capacity.
- Identify comparable geothermal areas within the EU based on the geothermal and geological setting, highlighting similarities and differences in the resource-base to compare with the UK.
- Identify the general technical barriers to resource development (geological, mechanical).
- Identify the general non-technical barriers to resource development (social, economic, political).

The discussion will be based on the above data with the aim of determining the main limiting factors on UK resource development based on the data gathered. The hypothesis for this Chapter is that country-specific technical and non-technical barriers preferentially hinder the UK from developing deep low-enthalpy geothermal resources.

3.4 Methodology

For the most part Chapter 3 is a literature-based review of existing data and target-country Government policy. The methodology for undertaking such a study, therefore, is based around a desk study of available information. A systematic approach to obtain the same data for each identified country will be undertaken. The source of data will determine the quality, and as such there is an element of scrutiny applied. The first part of the Results section includes the technical aspects of geothermal resources in each identified country (geological, mechanical). The second part of the Results section focuses on non-technical aspects (socio-political and economic data for identified countries). Data sources have been determined below.

Technical Data

- Government Agency (Geological Survey).
- Published literature (peer reviewed).
- Published literature (non-peer reviewed).

Non-Technical Data

- European-led Directives.
- Country specific legally binding Directives.
- Country-specific guidance documentation.
- Published literature (peer-reviewed).
- Published literature (non-peer reviewed).

It is noted some data sources may be more robust than others, and as such each will be scrutinised for its quality.

Technical data for each country will be scrutinised to identify the following:

- Aquifer(s) exploited.
- Aquifer properties (porosity, permeability, thickness).
- Flow rate.
- Temperature of resource and thermal output.
- Number of installations and their location.
- Problems encountered with extraction, such as scaling and corrosion.
- Historical development of the resource.
- Total installed capacity.

Non-technical data will be scrutinised to identify the following:

- Specific Government policy relating to geothermal development.
- Incentives, payback tariffs and funding mechanisms to encourage the uptake of geothermal.
- Other available incentives and/or Government policy that may indirectly affect geothermal e.g. regulations to ensure new developments source a certain percentage of their energy from renewable sources.
- Risk insurance scheme availability.
- Licensing framework which directly addresses geothermal development.

Comparison of these key points will be undertaken to determine common trends or differences in the way geothermal is handled in each country. Discussion of the findings and concluding remarks regarding the state of deep geothermal resource exploitation in the UK will be presented as a result of this comparison.

3.5 Study Areas

The countries chosen for comparison with the UK have been determined not by installed capacity, but by geology and geological setting as this is what defines the type of geothermal resource available and will affect whether or not a resource exists. Determination of comparative study areas also cannot be based purely on installed geothermal capacity values primarily due to the difficulty in separating out shallow vs deep geothermal heat generation.

The work undertaken during 1986-1995 (Downing and Gray, 1986a; Rollin et al., 1995) identified the location of the UK's best quality geothermal resources based on available data; geothermal aquifers were identified and classified within specific geological successions as highlighted on Figure 3-5.

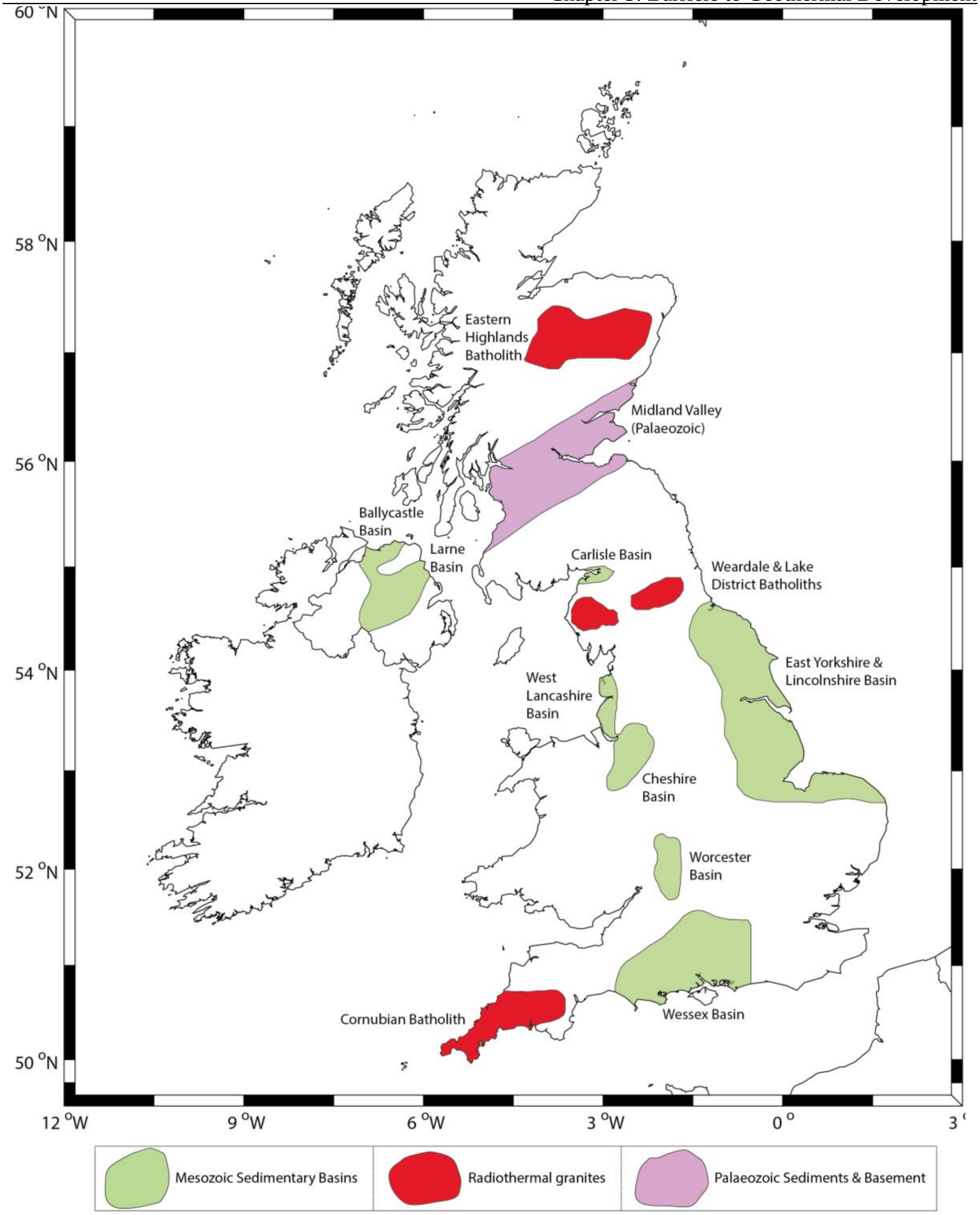


Figure 3-5: Location of Mesozoic Basins (Barker et al., 2000).

Geothermal research within the UK has previously focused on Mesozoic sedimentary basins; as has already been discussed the only geothermal aquifer currently being exploited is the Sherwood Sandstone Group (a Permo-Triassic sandstone located within the Wessex Basin of Southern England). The Sherwood Sandstone is also found within other basins across the UK and is similarly transmissive (Rollin et al., 1995) but not currently exploited for geothermal use.

Using the generalised geological map of Western Europe (West, 2002) presented in Figure 3-6, it can be seen that the same intercratonic basins underlie parts of France, Germany, the Netherlands, Denmark and the UK; the geological evolution of these areas are intrinsically linked through connection of the Anglo-Paris Basin (France-UK) and the North German/Danish Basin (Germany-Netherlands-Denmark-UK, also termed the Northwest European Basin – part of the larger Central European Basin). These countries have all posted figures for installed direct-use geothermal capacity so geothermal resources do exist within these countries. The geological evolution of these areas, and the subsequent likely distribution of potential geothermal aquifers and their properties, has been investigated because of linkage of large-scale European basins. If there are geological variations in the quality of aquifer this could in the first instance form a primary geological barrier to UK resource development.

Figure 3-6: Geological map of Europe highlighting shared intercratonic basins (Crampon et al., 1996; West, 2002).

3.6 Results: Geological Overview of Target Countries & Corresponding Basins

3.6.1 Introduction & Brief Geological History

Both the Anglo-Paris Basin and Northwest European Basin play host to large thicknesses of Permian-Tertiary aged sediments. Their main phase of development took place during the Permian as a consequence of large-scale extensional reactivation of Variscan-aged faults. In addition new rifts also developed towards the end of the Permian, continuing throughout the Triassic. Much of the sedimentation throughout the Permian was clastic in origin due to the presence of Pangaea. The Triassic saw onset of further rifting and a clastic-shallow marine-evaporite dominated sedimentary regime developed. This rifting can be seen more clearly within the Northwest European Basin.

The beginning of the Jurassic saw the breakup of Pangaea and a switch to widespread marine sedimentation. This was as a consequence of thermal relaxation linked to the opening of the Tethys Sea and the Atlantic Ocean along the Atlantic Margin. An initial marine transgression of the Tethys Ocean established a marine shelf covering both the Anglo-Paris Basin and large parts the Northwest European Basin. This marine-dominated setting continued throughout the Jurassic and into the Cretaceous (Mortimore et al., 2001). Whilst Laurasia and Gondwanaland broke apart, large accumulations of predominantly carbonates (chalk) were deposited during the Cretaceous across land areas within the basins of concern. Sea levels during the Cretaceous were at their highest. The Alpine Orogeny caused a return to a compressional stress system across parts of Europe causing inversion and deformation of basins along the pre-existing Variscan tectonic structures. Within the basins of concern this was followed by further subsidence of sub-basins during the Tertiary and the deposition of both clastic and carbonate lithologies.

A series of paleogeographic maps (Figure 3-7) taken from Ziegler (1980) display the changing paleogeography from Permian through the Tertiary Era to give further insight into the development of each basin.

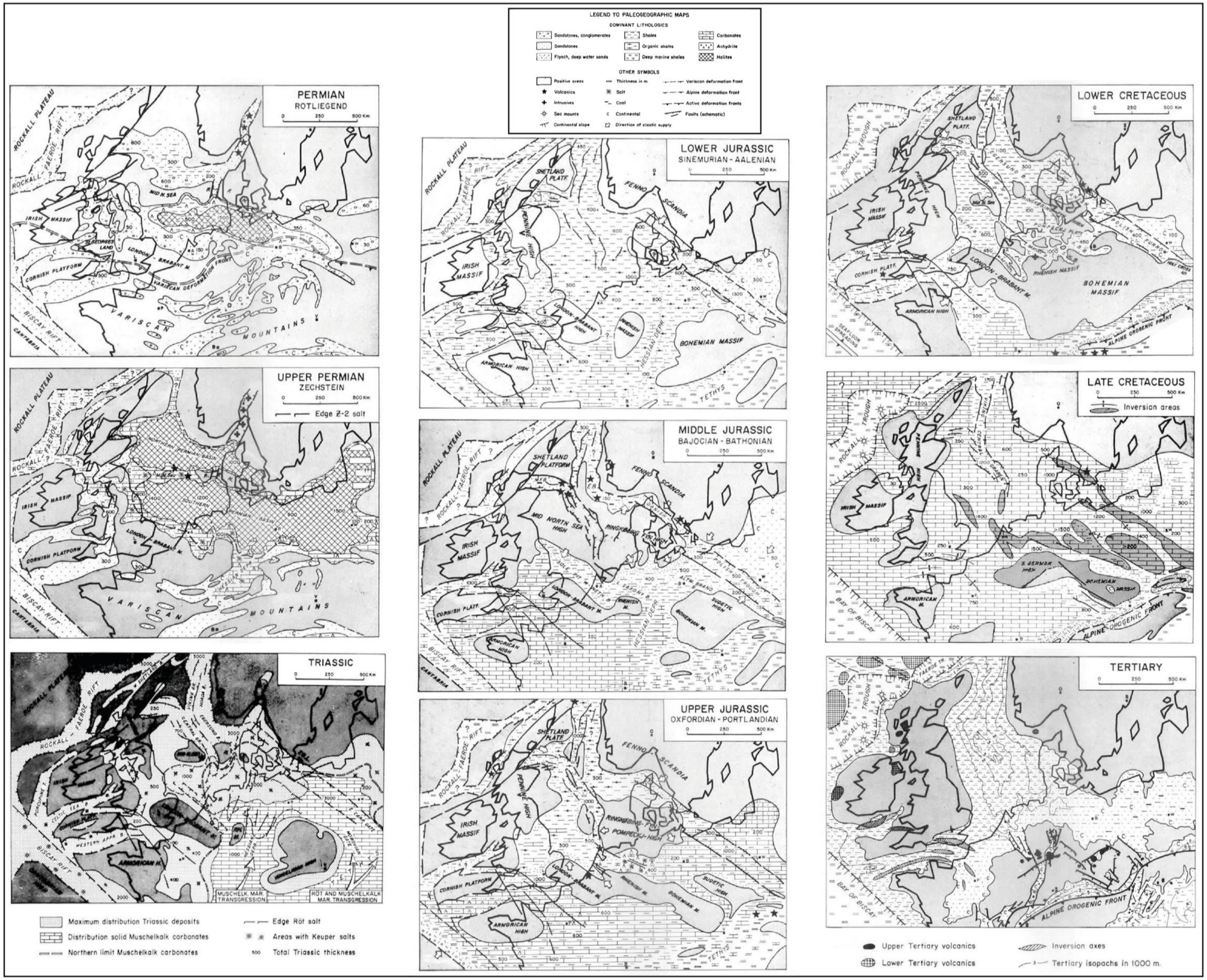


Figure 3-7: Paleogeographic reconstructions of Northwest Europe throughout the Permian, Triassic, Jurassic, Cretaceous and Tertiary (Ziegler, 1980).

3.6.2 The Anglo-Paris Basin

The main phase of development within the Anglo-Paris Basin occurred throughout the Jurassic, Cretaceous and Tertiary, so much so that >3 km sediment of Jurassic-Tertiary age has accumulated (Crampon et al., 1996; Ungemach and Antics, 2015). Despite appearing truncated by the English Channel the Anglo-Paris basin underlies northern France and southern England; the basin is linked underneath the English Channel forming the Wessex Basin (UK) and Paris Basin (France).

3.6.3 Northwest European Basin

Ziegler (1980) provides a comprehensive developmental overview of the Northwest European Basin. The basin itself can be broken down into a series of sub-basins. A brief summary is provided here, whilst Figure 3-8 provides further insight into the basin formation. The Northwest European Basin occupies an area of approximately 1.5×10^6 km^2 trending NW-SE, and is bound by the Elbe Fault System to the south and by the Tornquist Zone to the north. The basin is defined by a series of fault zones and sub-basins that includes the North German Basin (NGB). Rifting and deformation has occurred throughout Tornquist zone from late Carboniferous to more recent Cenozoic times.

During the Permian, the Northwest European Basin was split into two individual basins; the Northern Permian Basin and the Southern Permian Basin, split by the Mid-North-Sea-Ringkøbing-Fyn-Mon highs (Figure 3-8).

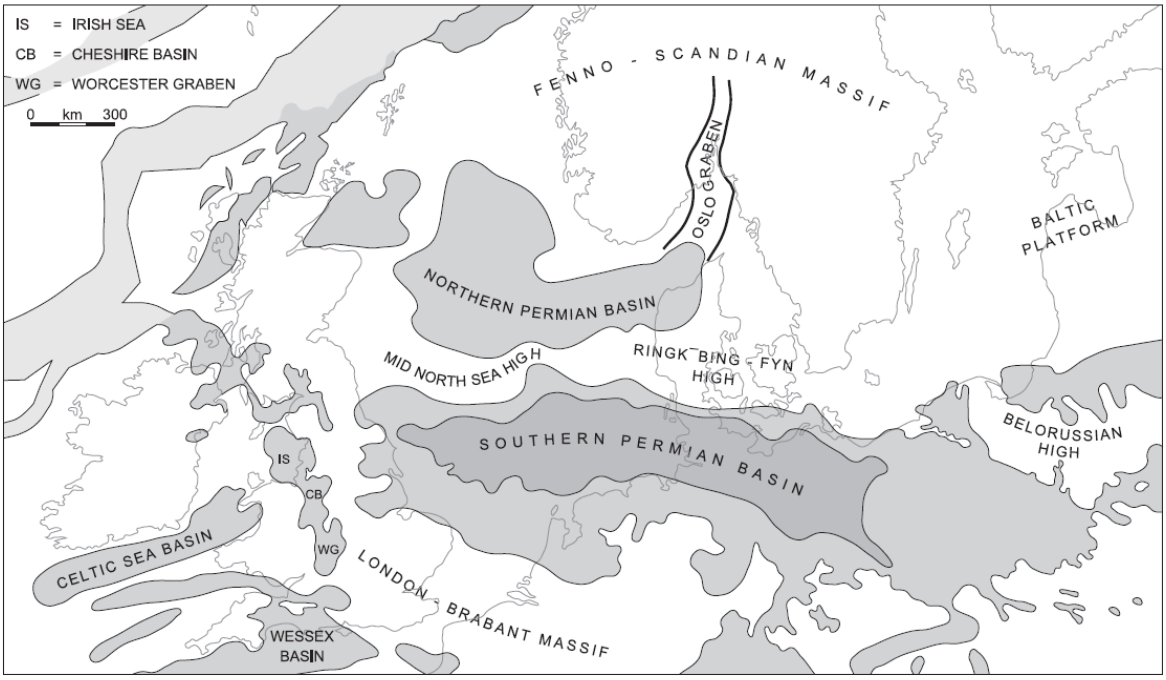


Figure 3-8: Paleogeography of the Permian Period across Northwest Europe showing the main depocentres. This includes the Northern Permian Basin and Southern Permian Basin. It also shows other Permian basins that developed contemporaneously to this across the UK (Underhill, 2003).

Despite the separation of these basins deposition of the Permian red-bed (Rotliegend) series took place at this time in both basins. The Southern Permian Basin is of more interest given it is this portion of the basin that underlies much of the Netherlands, the UK, Germany and Denmark. The basin was infilled with clastic sediments in a predominantly aeolian and sabkha depositional environment forming good quality aquifers at variable depth.

3.7 Identified Geothermal Aquifers: Overview

Figure 3-9 provides a comprehensive correlated overview of the identified geothermal aquifers within the UK, Germany, France, the Netherlands and Denmark. The correlation is necessary owing to the naming variations for each formation or group that has been classed as a geothermal aquifer. Figure 3-9 should be referred to throughout the rest of Chapter 3. Whilst there is certainly cross over of reservoirs between the identified countries, lateral variations in the aquifers across these areas require an understanding. Lateral variation will be explored further within Section 3.8 where information regarding the reservoir properties of the aquifer in each country will be described. In addition, the geothermal development history and current status for each country has been discussed.

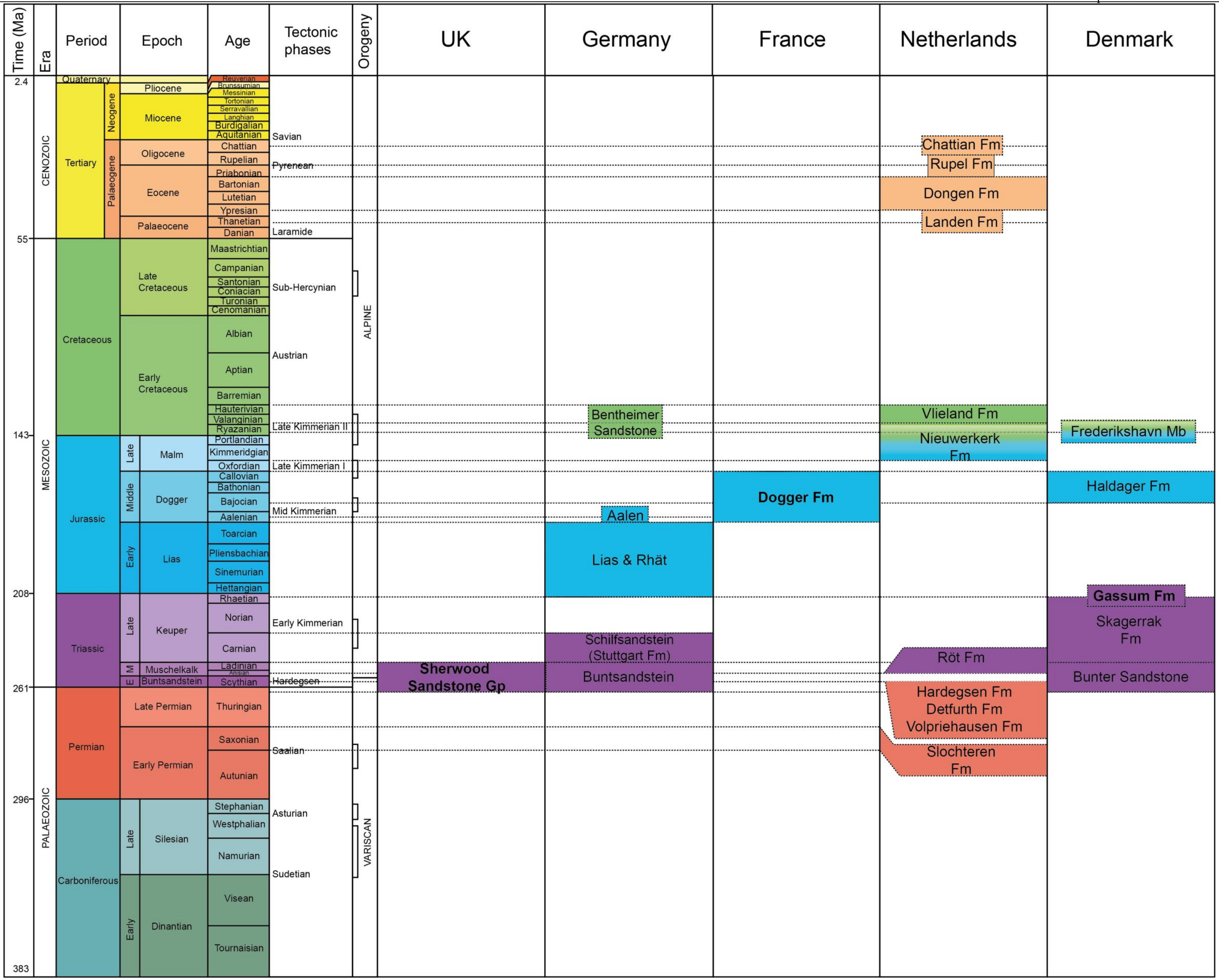


Figure 3-9: Correlation of geothermal aquifers across the UK, Germany, France, the Netherlands and Denmark. Geothermal aquifers were classified by Downing and Gray (1986b), Weber et al. (2015), Lopez et al. (2010), Kramers et al. (2012) and Røgen et al. (2015). Strata were correlated by cross referencing geological time periods between the International Chronostratigraphic Chart and nomenclature from the Geological Survey of the Netherlands (TNO) (2016).

3.8 Technical Assessment

3.8.1 France

3.8.1.1 Geological Overview

The portion of the Anglo-Paris Basin underlying northern France covers an approximate area of 110,000 km^2 (Lopez et al., 2010). The generalised geological map of France is presented in Figure 3-10, displaying the distribution of strata across the country. The Paris Basin forms the focus of study within Chapter 3 given the known linkage with the Wessex Basin of the UK.

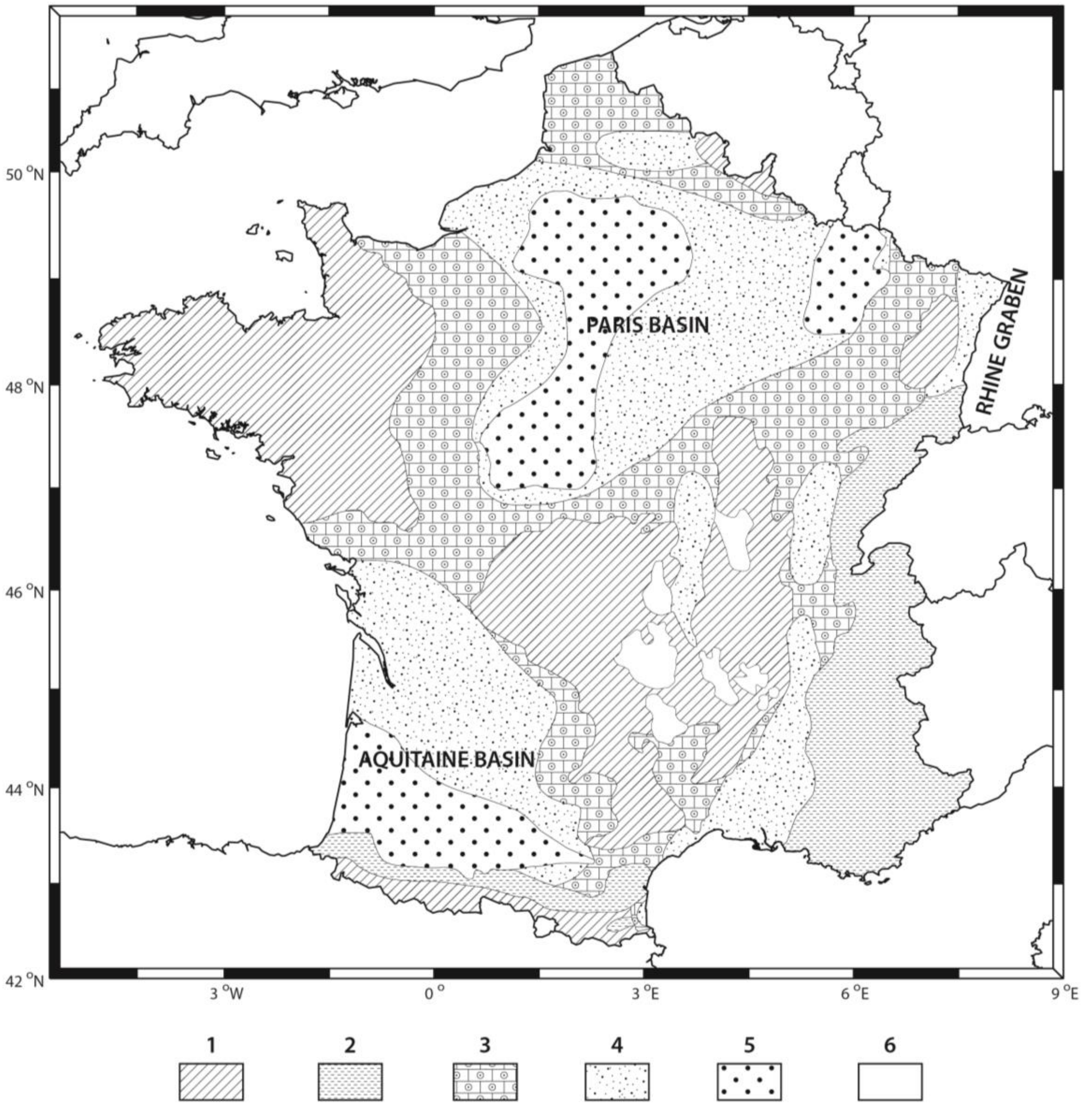


Figure 3-10: Adapted from the Global Energy Network Institute (2014). 1: Igneous bodies (discontinuous superficial aquifers). 2. Recent mountain chains (superficial discontinuous aquifers). 3. Shallow sedimentary basins (continuous aquifers). 4. Deep sedimentary basins (continuous aquifers). 5. Continuous deep aquifers, proven or probable resources. 6. Recent volcanic rocks.

3.8.1.2 Geothermal Overview

The Dogger Formation of the Middle Jurassic (Bathonian) forms the best quality geothermal reservoir within the Paris Basin. The Dogger Formation consists of carbonate sediments within which fluid flow is through both pore spaces and fractures (Lopez et al., 2010) allowing high-volume flow rates to exist. Permeability ranges between 2 and 20 Darcy whilst porosity averages 15%. The aquifer is found at depths of approximately 1500-2000 m with a productive thickness of up to 20 m. Downhole temperatures of 55-80°C are found across the basin (Lopez et al., 2010; Vernier et al., 2015). The average temperature gradient across the basin is 3.5°C per 100 m, with upper and lower limits of 4.1°C per 100 m and 2.75°C per 100 m respectively. Flow rates of 100-200 m^3 hr^{-1} are generally seen within the doublet systems across the basin but can be up to 300 m^3 hr^{-1}.

The Dogger Formation is described as having a finite geothermal resource as cooled re-injected thermal waters are unlikely to have time to re-equilibrate back to a temperature of 60-80°C before breaking through into a production well. More recently a shallower (650 m) Albian-aged aquifer has been exploited for water flowing at 200 m^3 h^{-1} and 28°C. The system has a heating thermal capacity of 5.4 MW_t and 1.3 MW_t for sanitary water. A Neocomian-aged aquifer also produces heat from 900 m / 34°C for 3500 homes (Vernier et al., 2015). Boissier et al. (2009) state the original resource lifespan was numerically modelled to be 15-20 years. However, doublets in the Paris region have been exploiting the resource for over 20 years with no thermal decrease yet noted. Issues with pumping equipment and corrosion/scaling have been problematic throughout the history of geothermal exploration in the area. The latter problem was easily solved by replacing and improving pump elements. However, the corrosion and scaling presents a larger problem. Water extracted from the Dogger aquifer currently produces water in a slightly acidic reduced state causing anoxic conditions within the production well. The carbon steel casing subsequently corrodes as a result of these conditions, in addition to precipitation of iron sulphide. As of 2012, >8 mg L^{-1} of corrosion inhibitors were required in all geothermal exploitation wells to counter the effects of corrosion and scaling (Castillo and Ignatiadis, 2012). These issues are confined to the Dogger aquifer.

Triassic sandstones form a secondary geothermal target within the Paris Basin. These units are found at depths between 2000 m and 3000 m but contain highly saline mineralised reservoir fluids that are problematic when cooled and re-injected. In the first instance the Triassic reservoirs have poorer re-injection properties when compared to the Dogger

Aquifer (permeability and porosity are reduced). Secondly, re-injection of cooled Triassic brines back into the Triassic reservoir causes problems with extraction of further fluids by precipitation of pore-occluding phases such as carbonates. Castillo et al. (2011) investigated the potential to re-inject into the Dogger aquifer instead but modelled predictions suggested calcium and dolomite precipitation is likely to occur within a 50 m radius around the well. However, the porosity is little affected and the work has yet to take into account redox-sensitive species such as iron and sulphur (although it is likely these phases will not be problematic as they can be mitigated through appropriate well design and altering injected fluid chemistry).

3.8.1.3 Geothermal Development

Geothermal exploration in the Paris basin was initially instigated in 1962 with the sinking of a well at Carrieres-sur-Seine, pre-dating the 1970's energy crisis that affected large parts of Europe. Extremely high (but unspecified) flow rates were found to exist within the target reservoir. However, due to the highly mineralised nature of the extracted brine it could not be discharged to surface watercourses and, therefore, the well was abandoned (Ungemach, 2001). The potential of the aquifer remained and a well doublet was commissioned at Melun l'Almont, south of Paris in 1969. A doublet allowed the reinjection of wastewater back into the aquifer, thus removing the environmental and financial issue of wastewater treatment and disposal. Wastewater treatment and disposal is something that would otherwise make geothermal development prohibitively expensive. Reinjection also allowed reservoir pressures to be maintained, and thus flow rates (Lopez et al., 2010). Further development of the Melun l'Almont site allowed new technologies to be implemented that included the sinking of a third borehole and novel well design. These new technologies allowed productivity to remain high whilst extending the lifespan of the pump and well screens. What was initially seen as an "exotic curiosity" (Ungemach, 2001) ultimately led to an explosion in geothermal development of the Paris Basin in subsequent years; these initial wells showed that geothermal energy was a viable option to provide a baseload of heat energy to Paris and its surrounds (Ungemach, 2001).

Currently across the Paris Basin there is a total of 278.5 MW_t installed thermal capacity producing 4311.8 TJ yr^{-1} from a possible 37 doublet or triplet systems (Vernier et al., 2015). The limitation of geothermal development within the Paris Basin is not due to decline in the resource temperature, but due to the technical limitations of the wells. The economic feasibility of maintaining a corroded well has caused the abandonment of at least 42 wells within the basin (Lopez et al., 2010).

3.8.2 UK

3.8.2.1 Geological Overview

A generalised geological map of the main geological units is shown in Figure 3-11. The UK is located on a tectonically stable craton; basement rocks have been steadily heated by conduction of heat produced within the earth. Rather than heat being distributed equally throughout the basement of the UK, thermal conductivity of the overlying rocks has determined the location of above average heat flow. Igneous intrusions have also modified heat flow. Heat is also transferred by deep groundwater circulation; upwelling groundwater flow can therefore be an indicator of enhanced heat flow at that location. Several warm springs have been identified at various locations (Bath, Bristol, Buxton and Taff’s Well) which are the product of deep circulating warm groundwater emanating from deep sedimentary basins (Younger et. al 2012).

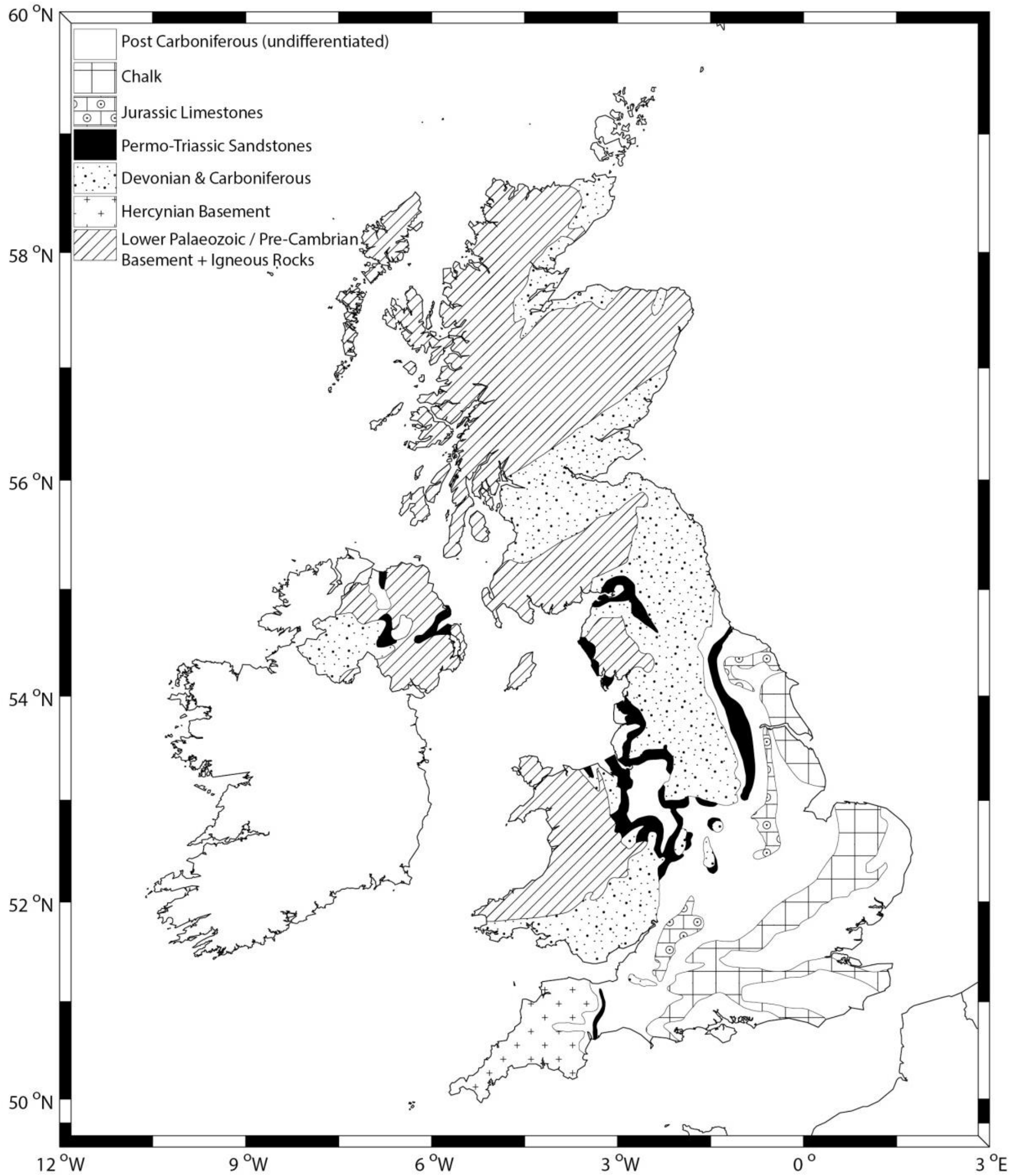


Figure 3-11: Generalised geology of the United Kingdom (Crampon et al., 1996).

3.8.2.2 Geothermal Overview

A comprehensive overview of the geothermal resources of the UK can be found in Chapter 2, Section 2.3. The pertinent points are that only one working deep geothermal system is currently operating within the Wessex Basin (the Southampton District Heating Scheme). The majority of UK installed geothermal capacity is accounted for by shallow ground source heat pumps (281.76 MW_t).

3.8.3 Germany

3.8.3.1 Geological Overview

The North German Basin (NGB) extent is defined as an area occupying the northern third of Germany and includes Dusseldorf, Hannover and Berlin. It formed as part of the larger scale Northwest European Basin (Central European Basin) and contains 2-10 km of Mesozoic and Cenozoic age sediment (Schellschmidt et al., 2010). The NGB is split into the Northwest German Basin (NWGB) and Northeast German Basin (NEGB). Tesmer et al. (2007) describes the general geological evolution of the basin, summarised herein. The basin formed as a consequence of several phases of subsidence that began at the end of the Carboniferous. Initially volcanics were deposited during the earliest Permian before the first phase of basin subsidence produced a clastic sequence of aeolian sand and fluvial playa deposits. The latter part of the Permian became occupied by the Zechstein Sea which, as a consequence, resulted in vast thicknesses of salt being deposited. A further set of marine transgressions and regressions occurred throughout the Triassic, Cretaceous and Jurassic producing a sequence of terrestrial sandstones and shallow marine carbonates.

Mesozoic and Cenozoic sediments have been intensely deformed due to related halokinetic movements (Weber et al., 2015) of the Zechstein salt units. Extension during the Jurassic initiated such movements. As such there is large variation in the thickness of individual beds within the sedimentary sequence as well as there being strong lateral heterogeneity (Schellschmidt et al., 2010; Weber et al., 2015). The lateral heterogeneity and thickness variation affects the geothermal potential across the whole basin making some areas more productive than others. The basin is currently overlain by Quaternary sediments which include silt, clay and gravel of glacio-fluviatile, fluvial and aeolian origin (BGR, 2015).

A summary geological map of Germany is presented in Figure 3-12.

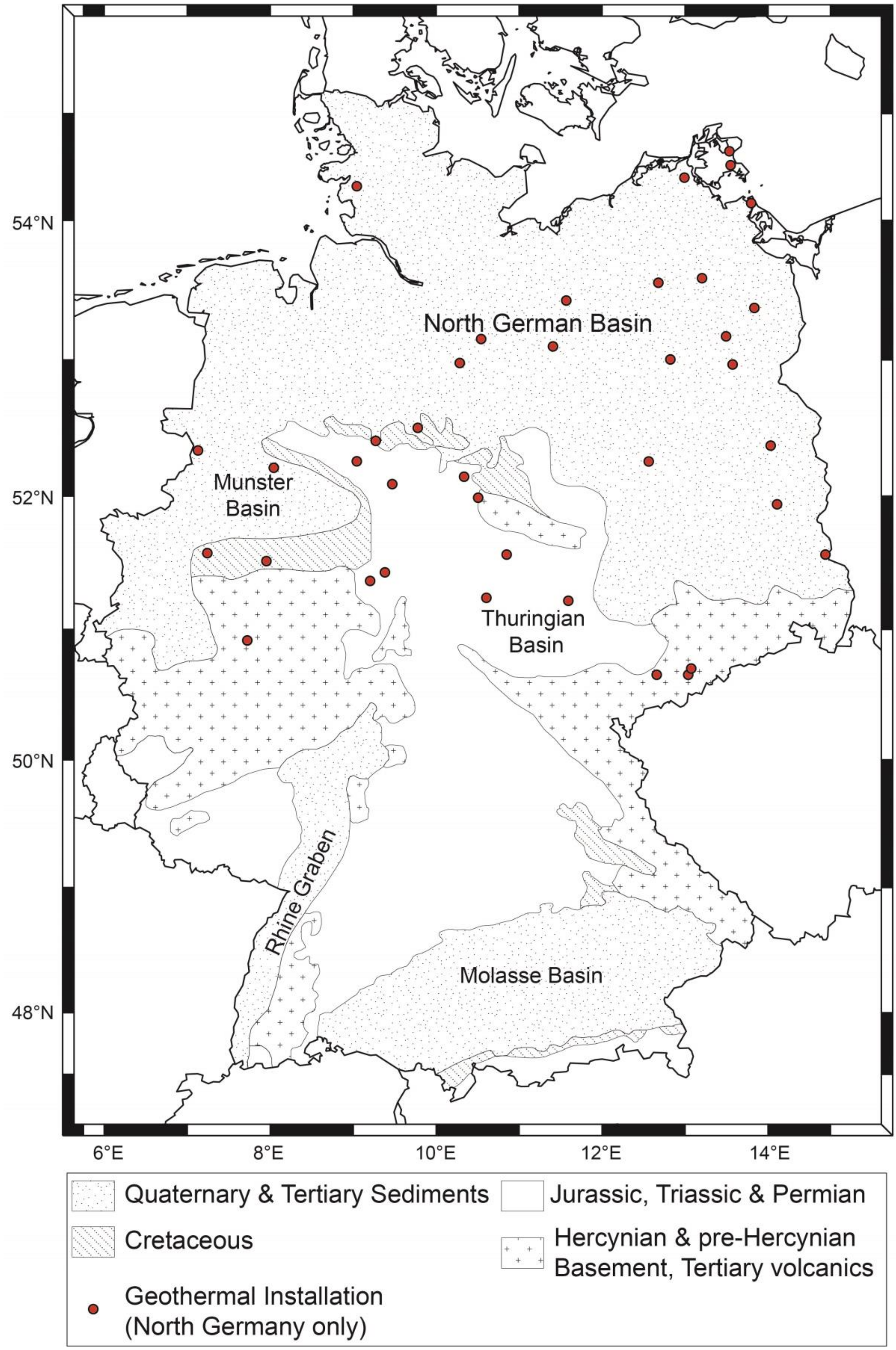


Figure 3-12: Summary geological map of Germany showing the main basins, after Crampon et al. (1996). Also included are geothermal installations located within the NGB (Agemar et al., 2014a).

3.8.3.2 Geothermal Overview

In contrast to the Anglo-Paris Basin there are six potential sandstone geothermal aquifers that have been identified within the NGB of Permian, Cretaceous, Jurassic and Triassic age. These have been summarised in Table 3-1. Temperatures have been taken from the top of the aquifer. The average depth to the aquifer has not been stated as it can vary by as much as 1000 m due to the distortion by Zechstein salt units. In this case, the quoted size of the resource is a more useful piece of information.

Table 3-1: Summary of identified geothermal resources in the NGB (Weber et al., 2015).

Aquifer	Temperature (°C)	Resource (EJ)
Valendis Sst	50	0.11
Bentheimer Sst	54	0.28
Aalen	43	80.83
Lias & Rhät	38	102.87
Schilfsandstein	48	37.88
Buntsandstein	49	70.88

Deep geothermal energy potential within Germany has been classified as aquifers >400 m below ground level at >20°C. Aquifers <60°C are typically used in spas, where flow rates have been reported to be approximately 1296 $m^3\ d^{-1}$ (Agemar et al., 2014b) from a single production well. Further flow rate data can be found in Table 3-2 (Agemar et al., 2014a). Information regarding the aquifer that has been exploited is not available.

Table 3-2: Summary of temperature and flow rate data for geothermal wells located within the NGB (Agemar et al., 2014a).

Name	Max. Temp (°C)	Max. Flow Rate ($m^3\ d^{-1}$)	Max. Depth (m)
Arnsberg Erlenbach 1	25	1900	586
Arnsberg Erlenbach 2 (tiefe EWS)	90	1728	2835
Bad Emstal	34	346	759
Bad Langensalza, Thermalsolebohrung 1996	no data	8.64	741
Bad Sulza, Bohrung Bad Sulza 1984 (Sole 84)	22.4	121	613
Bochum Zeche Robert Müser	20	1900	570
Heide	23	86	530
Karlshagen / Usedom	57	2419	1788
Kassel, Bohrung Wilhelmshöhe 2	40	155	793
Kassel, Bohrung Wilhelmshöhe 3	40	69	672
Neubrandenburg	80	2419	1268
Neuruppin	63.4	1201	1702
Neustadt-Glewe	99	3024	2450
Prenzlau	108	287	2786
Sassnitz - Dwasieden	30	769	1053
Stralsund	58	2419	1603
Waren / Müritz	63	1469	1565

Additional production rate data from the Rhaetian (Rhät) aquifer ranged from 950 $m^3 d^{-1}$ (Neubrandenburg and Neustadt-Glewe) to 3024 $m^3 d^{-1}$ (Neustadt-Glewe – Agemar et al. 2014b). Flow is predominantly through pore space with a limited amount of fracture flow.

The temperature gradient for the NGB has been averaged from data taken from Agemar et al. (2014a), Bozau and van Berk (2013), Regenspurg et al. (2010), Seibt et al. (2005), Seibt and Kellner (2003), Fuchs and Förster (2014), Norden et al. (2008) and Kabus and Jäntsch (1995), shown in Figure 3-13. The average geothermal gradient across the basin has been calculated to be 33°C km^{-1}.

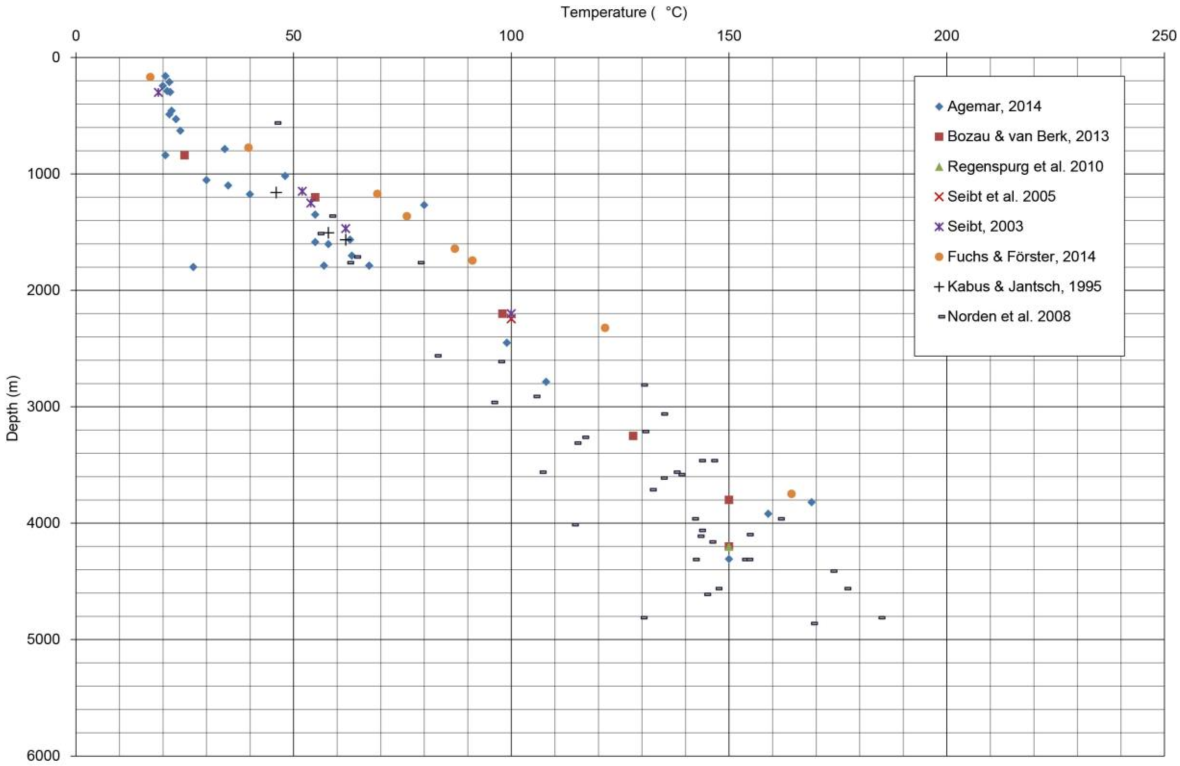


Figure 3-13: Temperature data from Agemar et al. (2014b), Bozau and van Berk (2013), Regenspurg et al. (2010), Seibt and Kellner (2003), Seibt et al. (2005), Fuchs and Förster (2014), Kabus and Jäntsch (1995) and Norden et al. (2008).

Aquifer thickness varies across the basin. Within the NEGB there is a variation between the NW and SE as evidenced by the work undertaken by Tesmer et al. (2007) shown in Figure 3-14. Within the NWGB the thickness of aquifers varies from several metres to approximately 100 m.

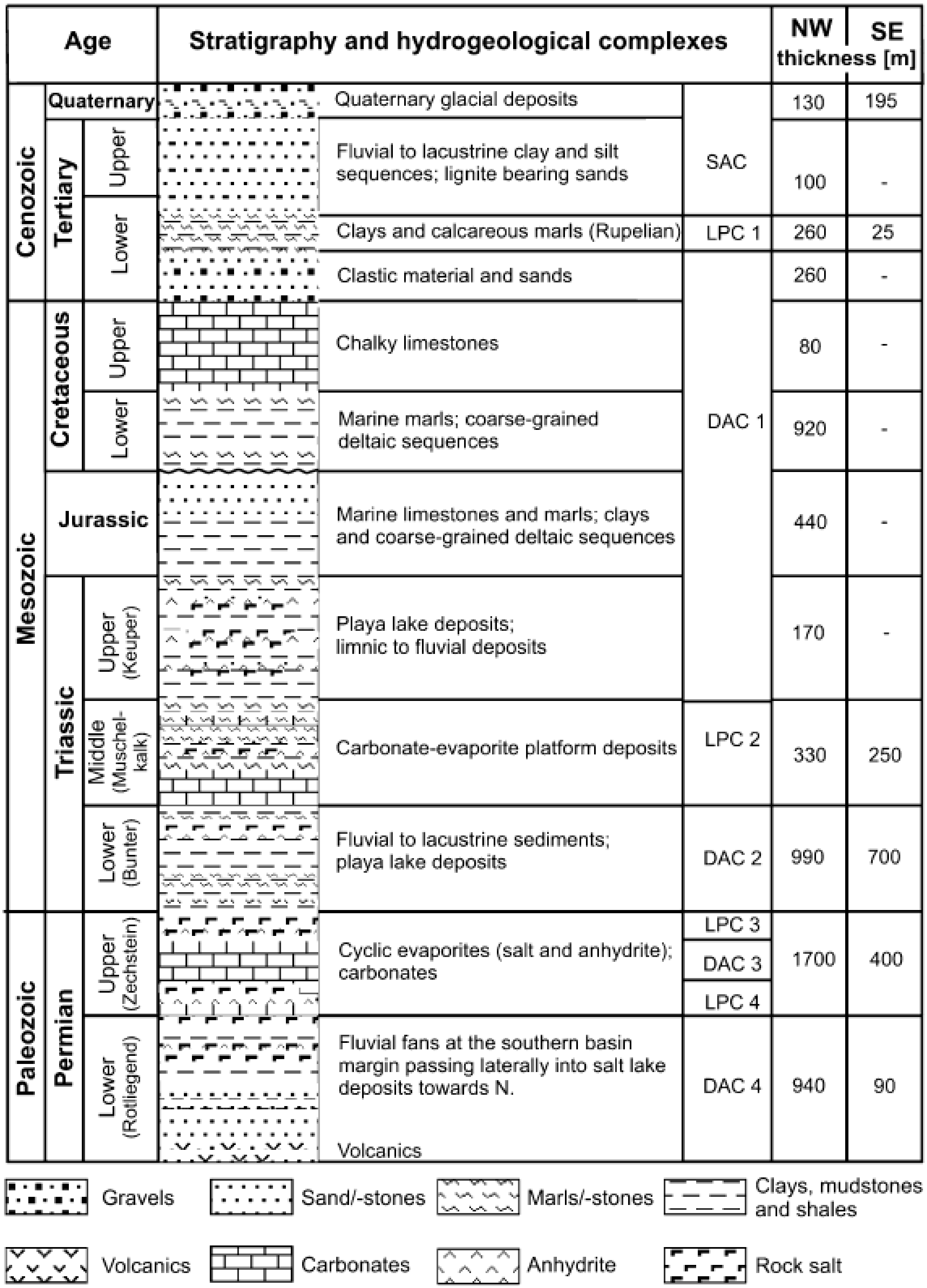


Figure 3-14: A comparison of the main lithological and hydrogeological sequences in the across the NW and SE portion of the NEGB.

A limited amount of porosity and permeability data are available for four geothermal installations within the basin (Huenges et al., 2004; Kabus and Jäntsch, 1995; Seibt et al., 2000; Seibt et al., 2005) detailed in Figure 3-3.

Table 3-3: Poroperm data for four geothermal installations within the NGB.

Installation	Porosity (%)	Permeability (mD)	Thickness (m)	Stratigraphic Unit
Neustadt-Glewe	22	200-800	57	Keuper/Rhaetian
Waren-Papenburg	27-29	500-2000	24-30	Jurassic/Triassic
Groß Schönebeck	10	-	-	Rotliegend/Permian
Neubrandenburg	20-34	300-1500	-	Triassic/Keuper

3.8.3.3 Geothermal Development

The first geothermal development located within the NGB was at Neustadt-Glewe, developed in 2003. Neustadt-Glewe was the first deep geothermal scheme to be successfully implemented within Germany. The installed geothermal capacity at this well is currently 4 MW_t, producing from fluids extracted at 99°C from 2450 m; the water is used for district heating. A second plant at Landau (Rhine Graben) was installed in 2007 and was the first to produce electricity as well as heat. There has in the past been some installed capacity for electrical generation within the NGB but currently there is zero installed capacity (Agemar et al., 2014a). The exploited low enthalpy resource within the basin is used for spas, space heating and district heating.

There are currently 38 geothermal installations within the NGB, displayed on Figure 3-12. Of these, 14 are currently in operation and have a total capacity of 45.21 MW_t and a geothermal capacity of 10.68 MW_t. A further 2.4 MW_t are under construction. Annual production from these installations totals 28.87 GWh (Agemar et al., 2014a).

Geothermal wells drilled within the basin have experienced problems with creep when Zechstein salt intervals have been encountered. The well at Groß Schönebeck, drilled in 2006-07, became plugged by creeping salt deposits as there had been incomplete mud displacement during cementation of the casing. It was possible to side-track the section affected, however, and the well was still completed ahead of schedule (Huenges, 2010).

Some minor induced seismicity has been encountered at Landau, Rhine Graben, measuring 2.4 and 2.7 on the Richter scale (Foulger et al., in prep.). However, these incidents only occurred after two years of successful production from the installed doublet (one well has been hydraulically stimulated). With questions over the location of hypocentre of the earthquake, no major changes at this installation have been undertaken.

The geothermal scheme at Staufen im Breisgau, southwest Germany, experienced ground swell and uplift during drilling due a phase change in an anhydrite layer. The addition of water created gypsum with the subsequent volume change causing damage to 269 buildings since 2007 (Lubitz et al., 2014). Although not directly related to the NGB, the presence of anhydrite is possible given the large volumes of Zechstein salt deposits.

3.8.4 The Netherlands

3.8.4.1 Geological Overview

The geological development of the Netherlands is described by the development of the Southern Permian Basin and Northwest European Basin. The country is occupied by a familiar block-and-basin style structural makeup that is controlled by pre-Variscan and Variscan basement faults, and is described comprehensively by Duin et al. (2006). A consequence of the reactivation of these faults has been multiple phases of extension and subsequent subsidence throughout the Permian, Triassic and Jurassic. The most important of these extension phases are of Late Jurassic-Early Cretaceous age (Duin et al., 2006). Movement during the Late Jurassic-Early Cretaceous time has affected the distribution and preservation of Permo-Triassic lithologies and control the main structural features of the Netherlands subsurface.

Early Permian sediments are dominantly terrestrial facies prior to the formation of the marine Zechstein and widespread salt formation (late Permian). Thickness variation across the Netherlands in the Zechstein is observed; some areas have seen halokinesis as a result of tectonic activity whereas more tectonically stable areas represent the original thickness of deposits. Distortion due to halokinesis is seen most strongly in the northeast of the country.

Due to Late Jurassic / Early Cretaceous extension and the creation of basins and platforms, these areas were subsequently subjected to erosion. Platform areas have lost Permian and Triassic sediment cover whilst basins form the location of both Permian and Triassic sediments. Eroded material forms the sediment input into the basins that had been formed contemporaneously to the platform formation. A period of basin inversion followed this extensional phase in the Late Cretaceous that has correspondingly removed Jurassic and Lower Cretaceous from all but the most actively subsiding basins and from platform areas. Both marine and terrestrial deposits were deposited throughout the Jurassic and Lower Cretaceous. Chalk of the Late Cretaceous has been preserved variably across the country due to inversion of varying magnitudes during the Cenozoic as a consequence of the Alpine Orogeny.

Approximately 95% of the country is covered by Holocene and Pleistocene deposits with only 5% being older (Late Cretaceous chalk). Figure 3-15 shows the main structural features pertaining to Jurassic and Early Cretaceous basins, whilst Figure 3-16 shows a cross section to display the complexities of the Netherlands subsurface. The lines of section are highlighted on Figure 3-15.

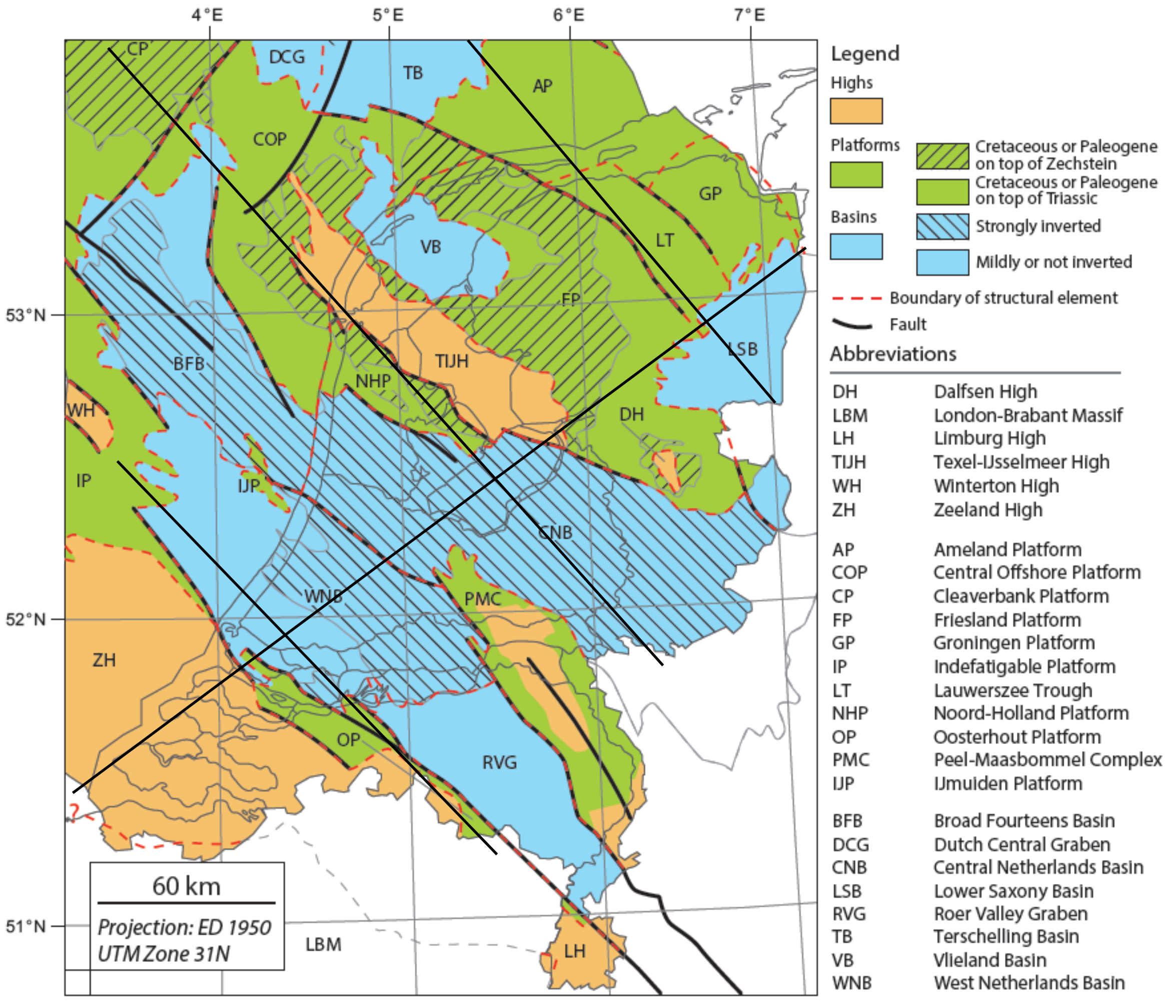


Figure 3-15: Structural elements of the Netherlands showing the Jurassic and Early Cretaceous basins, highs and platforms (Bonté et al., 2012).

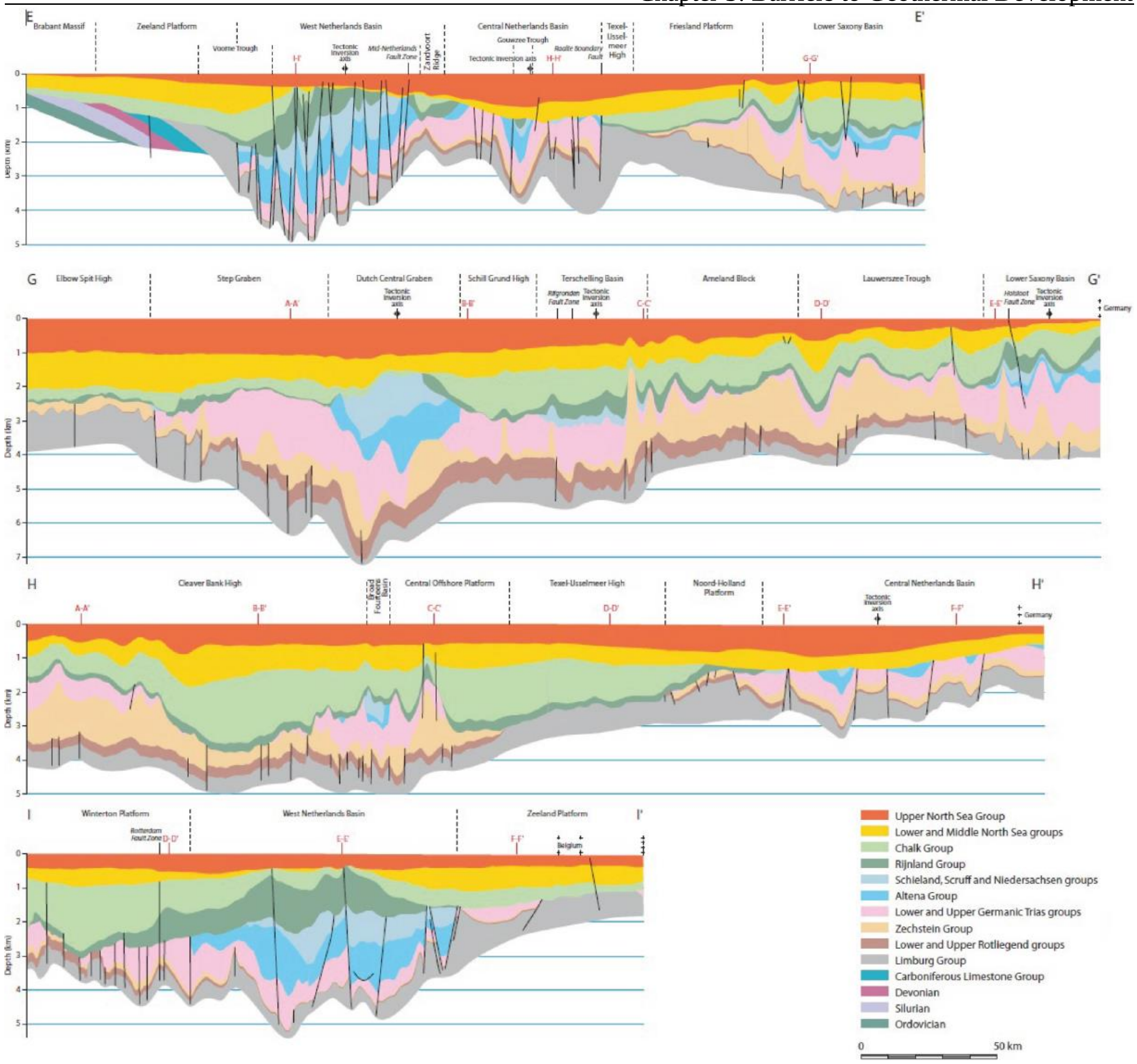


Figure 3-16: Cross sections referenced in Figure 3-15 showing the general subsurface relationships across the Netherlands (Duin et al., 2006).

3.8.4.2 Geothermal Overview

A total of five stratigraphic groups have been identified that could be exploited for geothermal purposes (Kramers et al., 2012). Within these groups, 11 stratigraphic formations have been identified. The following aquifer parameters have been summarised by Lokhorst and Wong (2007) in Table 3-4.

Table 3-4: Summary of geothermal aquifer properties (Lokhorst and Wong, 2007)

Aquifer		Depth (m)	Gross Sand Thickness (m)	Porosity (%)	Permeability (mD)	Temperature (°C)	Heat-In-Place (EJ)
Permian, Rotliegend sandstones	Groningen, Friesland, Drenthe & Noord-Holland	2000-4500	10-200	11-25	30-600	Max. > 100	50
Lower Triassic sandstones	West Netherlands Basin & Roer Valley Graven (Zuid-Holland & Noord Brabant)	2000-4000	25-300	Variable	Variable	Max. > 100	30
	Lower Saxony Basin (locally)	2000-3500	Max. 80	Variable	Variable	Max. > 100	3
	Other areas	300- >5000	0-50	Variable	Variable	Max. > 100	4
Lower Cretaceous sandstones	West Netherlands Basin (Zuid-Holland)	700-2500	Max. 250	15-30	Max. 3000	Max. 90	3
	Lower Saxony Basin (especially SE Drenthe)	800-1800	3-65	15-20	220-500	40-80	0.4
	NW Friesland	1800-2100	10-200	15-22	1-30	70-80	
Tertiary sands	Brussels Sand Mbr	100-1150	0-135		Max. 600	15-45	
	Breda Fm	<835	Variable	30-35	50- >200		
Total Heat-In-Place							> 90.4

A map showing the distribution of geothermal aquifers across the Netherlands is presented in Figure 3-17.

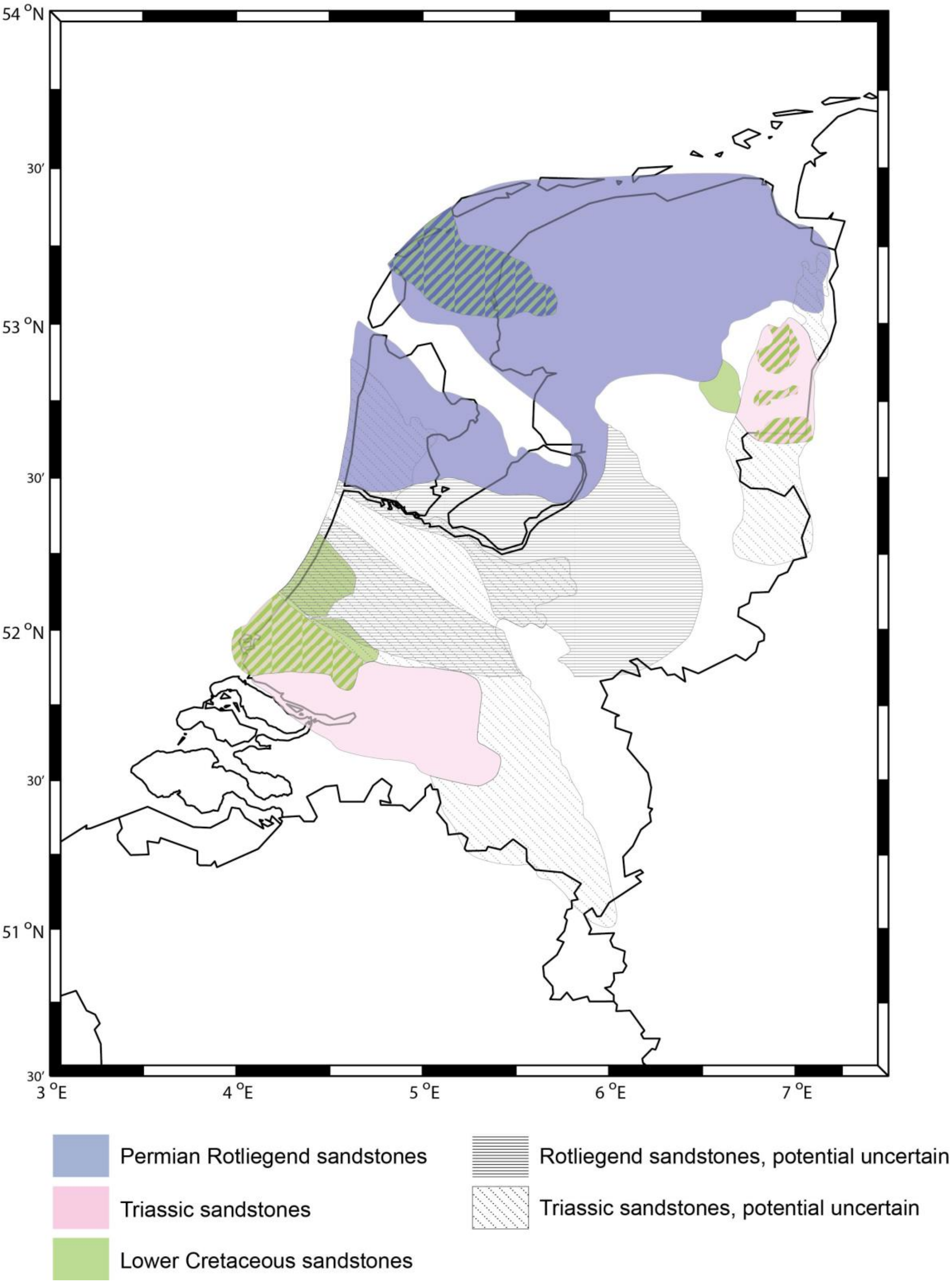


Figure 3-17: Aquifers within the Netherlands that have geothermal potential (Van Wees et al., 2010).

Temperatures of current installed geothermal wells vary between 60°C (1600 m) and 87°C (2900 m); the average geothermal gradient across the Netherlands has been calculated to be 31°C km^{-1} (van Heekeren and Bakema, 2015).

3.8.4.3 Geothermal Development

Shallow geothermal resources were first developed within the Netherlands in the 1980's. These resources were initially used to store solar energy as heat within the shallow subsurface (temperatures ranging between 7°C and 17°C). Deep geothermal was assessed between 1980 and 2000. However, initial research was unsuccessful in stimulating development of deep geothermal resources. A 1.6 km exploration well was sunk at Asten, Noord-Brabant in 1987 (Asten-2). Target formations (the Tertiary Houthern, Dongen and Breda Formations, Voort Member and Oligocene Rupel Formation) did not perform as well as expected, however, and the well was shut in. The failure at Asten caused a cessation in R&D for deep geothermal within the Netherlands (Kramers et al., 2012). A geothermal resurgence was not seen until oil prices began to rise once again in the 2000's. In 2007 a system containing two doublets at Bleiswijk was installed by a horticulturalist to heat greenhouses producing tomatoes. The wells exploit Lower Cretaceous sandstones at 1750 m with an extraction temperature of 60°C and produces 5 MW_t used to heat 14 Ha of greenhouses (Kramers et al., 2012; van Heekeren and Bakema, 2015; Van Wees et al., 2010). The Bleiswijk system formed the leverage to place geothermal resources back onto the renewable agenda within the country.

The applications for geothermal licenses decreased in 2010 due to co-produced methane. Stricter licensing conditions stipulated the well-head design was to be modified to cope with co-produced methane at the surface. Since 2010 it has become the choice of individual developers as to whether they extract and use the methane, or keep the extracted fluid pressurised to re-inject without methane extraction (van Heekeren and Bakema, 2015).

Currently there are nine geothermal installations within the Netherlands, with a further four under construction. The current installations supplied 268 GWh heat in 2013 (van Heekeren and Bakema, 2015).

3.8.5 Denmark

3.8.5.1 Geological Overview

The solid geology of Denmark is masked by a thick Quaternary drift sequence; bedrock geology is fragmented and mostly only exposed in coastal sections. The solid geology is part of the Northwest European Basin and shares a common geological evolution with both Germany and the Netherlands.

The area occupying the south of Denmark is part of the North German Basin, an area already described within Section 3.8.3. Additional notes to the description of the Danish portion of the NGB area are not required as a result. The central part of Denmark is occupied by the Ringkøbing-Fyn High; these are basement blocks of Pre-Cambrian age that bisect the country and are covered by a thin (1 km) sedimentary sequence (Røgen et al., 2015; Ziegler, 1980). The Norwegian-Danish Basin lies to the north of the Ringkøbing-Fyn High on a WNW-ESE trend, and it is within these sequences that the most promising geothermal resources can be found. A description of the structural and sedimentation history of Denmark is provided by Comité National Français de Géologie (1980), summarised below (Berendsen, 2005).

The northern margin of the Danish Basin is defined by the Variscan Tornquist zone; a complex faulted zone. These structures then became the controlling structures when further rifting occurred along the same lines of weakness throughout the Triassic, causing the formation of the Danish Basin. The Danish Basin links into the northern Permian Basin of the North Sea, separated from the southern Permian Basin by the Mid North Sea - Ringkøbing - Fyn High. Despite the separation, both basins had similar depositional systems during the Zechstein; thick mudstone-carbonate-anhydrite-halite sequences are found across both basins, fringed by limestones. Triassic sediments in the Danish Basin correlate with the NGB with the addition of two anhydrite layers. Similar depositional conditions prevailed across the basin throughout the Triassic producing fluvial sandstones, deltaic sandstones, mudstones and shallow marine deposits as a consequence to several transgressions and regressions caused by continued extension. The Jurassic marked a new phase of block-faulting in a similar fashion to that seen in the Netherlands; whilst basins subsided and provided a range of deposits due to many marine transgressions and regressions (fluvial, deltaic, shallow marine, deeper marine), blocks were actively uplifted. As a consequence these areas contain very little or no Jurassic cover. On average the Jurassic is 700 m thickness across Denmark. The Cretaceous was a relatively tectonically quiescent time with some subsidence occurring throughout the period. The sediments deposited during the early Cretaceous can be correlated across the NGB and across the North Sea, and are comprised of carbonate sequences. The major transgression seen in Late Cretaceous times affected the UK, France, the Netherlands and Germany; thick deep water carbonates (chalk) were accumulated across these areas, fringed by greensands. Marginal sequences in the Danish Basin tend to be coarser but also thinner than those seen in other basins. Approximately 1-2 km of Late Cretaceous deposits are found within Denmark. Towards the end of the Cretaceous a phase of basin inversion occurred causing uplift and wrench faulting across the Danish Basin.

The Tertiary saw the formation of the Tertiary North Sea Basin which has accumulated up to 2.5 km of sediment.

Figure 3-18 displays the main structural features that underlie Denmark.

3.8.5.2 Geothermal Overview

Five geothermal aquifers have been identified within the Danish Basin and NGB that underlies Denmark. These are noted as the following:

- Bunter Sandstone (Lower Triassic).
- Skagerrak Formation (Triassic).
- Gassum Formation (Upper Triassic / Lower Jurassic).
- Haldager Sand Formation (Middle Jurassic).
- Frederikshavn Formation (Upper Jurassic / Lower Cretaceous).

Figure 3-18 shows the current mapped subsurface distribution of these units along with other major structural features. It also shows the location of existing geothermal plants. Within the Danish Basin, the Bunter and Gassum are purported to be the best quality geothermal targets owing to their depth and facies. The Skagerrak displays a strong lateral heterogeneity and as such the quality of the Skagerrak is somewhat unknown. Shallower targets (the Haldager and Frederikshavn) are generally only found in the north of the country but form a shallow aquifer resource (Røgen et al., 2015). Within the NGB only a small area has preserved the Gassum Formation at useable depths. The only other geothermal resource in this area is the Bunter.

Flow rates, temperatures and depths of the Gassum and Bunter reservoirs can be found in Figure 3-5 and 3-6.

Table 3-5: Summary of aquifer properties for geothermal reservoir units in Denmark (Mathiesen et al., 2013)

Geothermal Plant	Gross Thickness (m)	Net Reservoir Sand (m)	Average Porosity (%)	Gas Transmissivity (D m)	Fluid Transmissivity (D m)	Pay Zone (m)
Thisted (Gassum)	135	83	27	185	100-110	30
Copenhagen (Bunter)	299	60	20	16	12	28
Sønderborg (Gassum)	61	39	39	240	129	35

The Haldager Sand is described as a medium to coarse fluvial-estuarine or braided river sandstone with porosity ranging between 15% and 30%. The thickness of the unit varies depending on the proximity to subsiding faults in the basin. The deposits closest to the Ringkøbing-Fyn High (within the Sorgenfrei-Tornquist Zone – Figure 3-18) attain thicknesses of 30-175 m. Further north these deposits thin to a maximum thickness of 50 m.

The sandstones of the Skagerrak Formation are described as arkosic fine to coarse grained sandstones deposited in alluvial/braided river systems. Data regarding the Skagerrak reservoir and the Frederikshavn Formation are not quoted in geothermal literature. They are currently not exploited for geothermal purposes (Mathiesen et al., 2010).

The measured temperature gradient across Denmark lies between 22-28°C km^{-1} which is somewhat lower than gradients seen for surrounding countries.

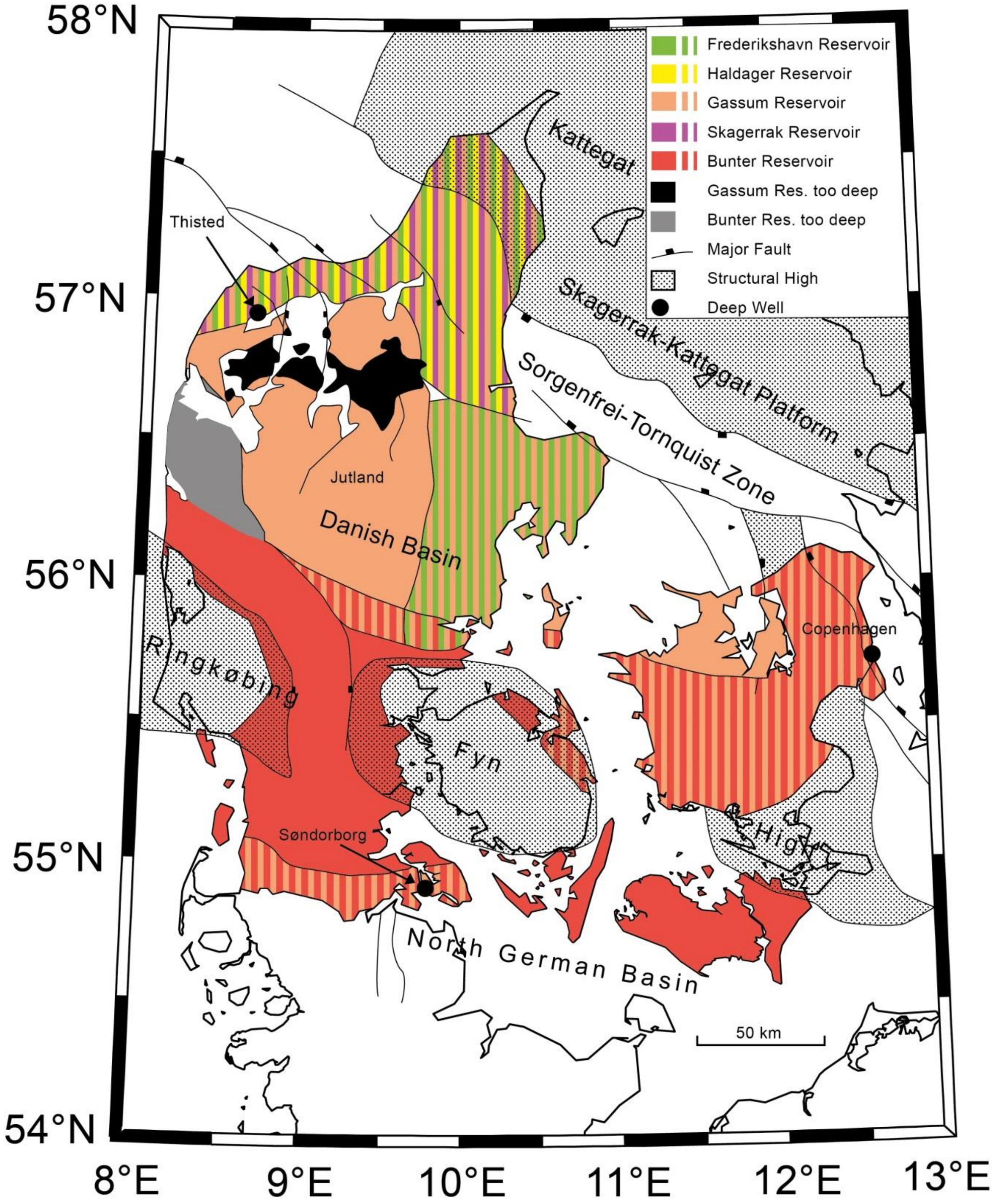


Figure 3-18: Distribution of geothermal aquifers within Denmark (Røgen et al., 2015).

The Geological Survey of Denmark and Greenland (GEUS) and the Danish Geothermal District Heating (DFG) determined the following requirements for a geothermal reservoir (Mathiesen et al., 2013):

- 10-50 m thickness.

- Located at 800-3000 m depth.
- Dominated by medium-coarse grained sandstones.

Diagenesis has been identified as problematic in sandstones >2500 m depth limiting the temperature of geothermal resources to 80-90°C.

3.8.5.3 Geothermal Development

The first geothermal installation within Denmark was at Thisted (Figure 3-18), developed in 1984. It took until 2005 for the second geothermal plant to be brought online at Copenhagen (Margretheholm). The current installed capacity within Denmark totals 353 MW_t. Of this, 33 MW_t is derived from three deep geothermal wells (Røgen et al., 2015), the remainder being derived from shallow geothermal resources. The three geothermal plants that are currently operational are summarised below in Figure 3-6.

Table 3-6: Breakdown of current installed capacity of geothermal installations within Denmark (Røgen et al., 2015)

Geothermal Plant	Installed Capacity (MW_t)	Flow Rate (m^3 h^{-1})	Temperature (°C)	Reservoir	Depth (km)	Date
Thisted	7	200	43	Gassum	1.25	1984
Copenhagen	14	235	74	Bunter	2.6	2005
Sønderborg	12	350	48	Gassum	1.2	2013

These geothermal systems are all comprised of one injection and one production well, but the heat that drives the heat exchanger is provided by a biomass boiler. The use of a biomass boiler means power is also produced at some locations.

Issues affecting injection have been encountered at all Danish deep geothermal plants due to salinity of extracted fluids and subsequent corrosion and scaling. An extensive program of soft acidification and well cleaning has been, and still is, in progress (Røgen et al., 2015).

3.9 Non-Technical Assessment – Overview

3.9.1 Social, Political and Economic Considerations

The EU is committed to reducing CO_2 emissions by 20% by 2020, and 80% by 2050. The legal framework under which all EU countries must abide by to achieve the reduction in CO_2 is the Renewable Energy Directive. Each country has been given an individual target based on the level of access to renewable energy streams and have all produced a National Renewable Energy Action Plan (NREAP). If a country can produce energy through renewable means with relative ease due to being located in an area that can produce a large proportion of energy sustainably, its target is increased. If there are limited opportunities to develop renewable low carbon technologies the target is reduced. Below are the targets as laid out in country-specific NREAPs.

- France – 23% of total final energy consumption to come from renewables. By 2020, energy consumption from residential/tertiary buildings to be reduced by 38%.
- Germany – 18% of energy to come from renewables by 2020. Currently the Federal German Government estimates they will have 19.6%.
- The Netherlands – 14% renewable energy by 2020. The National Renewable Energy Plan states 11 PJ are to come from geothermal by 2020, and a guarantee scheme must also be produced.
- UK – 15% from renewable energy by 2020. Of this, 30% electricity demand, 12% heat demand and 10% transport demand will be provided by renewables.
- Denmark – 33% of renewable energy by 2020.

Within each country, therefore, there will be a drive to implement and develop low carbon technologies to hit these targets. Many Northwest European countries have been reliant on petroleum and as such find development of low-carbon technologies a challenge, but one that there is a level of commitment to tackle. The policies, incentives and commercialisation of geothermal within each country will be presented further within Section 3.9.

3.9.2 General EU Funding Streams

The EU has released the European Energy Innovation Funding – 2016 Horizon 2020 call; €6bn is available over the period 2014-2020. Currently, 2016 in particular has a budget of €500m. The topic areas for application include a low carbon technology development fund amounting to €120m including Photovoltaics (PV), Concentrating Solar Power (CSP), wind, ocean energy, solar heating, hydropower, Combined Heat and Power (CHP), bioenergy, Carbon Capture and Storage (CCS) and **geothermal**. Individual project budgets will range from €0.6-10m.

The European Regional Development Fund is designed to reduce imbalance between regions by increasing economic and social cohesion. The areas it concentrates on are innovation and research, the digital agenda, supporting small-medium sized enterprises and the low carbon economy. The European Regional Development Fund, therefore, can be used for geothermal development and is currently open for applications.

3.9.3 Geothermal Organisations

Geothermal organisations formed from industry, academia and Government agencies are important in furthering geothermal regulation and policy to improve uptake of geothermal resources. These organisations can be the driving force in creating successful systems, combining a wide range of expertise and knowledge to provide guidance to policy makers. The organisation should be affiliated to the International Geothermal Associated (IGA) to ensure dissemination and sharing of knowledge. For each country the following geothermal organisations are present and affiliated to the IGA.

- UK – Renewable Energy Association (REA).
- Germany – Bundesverband Geothermie.
- France – Association Française des Professionnels de la Geothermie (AFPG).
- Netherlands – Stichting Platform Geothermie.

Denmark does not currently have a geothermal association affiliated to the IGA.

In addition to the geothermal associations described above, the European Geothermal Energy Council (EGEC) is another membership-based organisation that invites academic institutions, industry and country specific geothermal organisations to apply. All countries barring Denmark have organisations affiliated to EGEC and the IGA in the structure denoted in Figure 3-19.

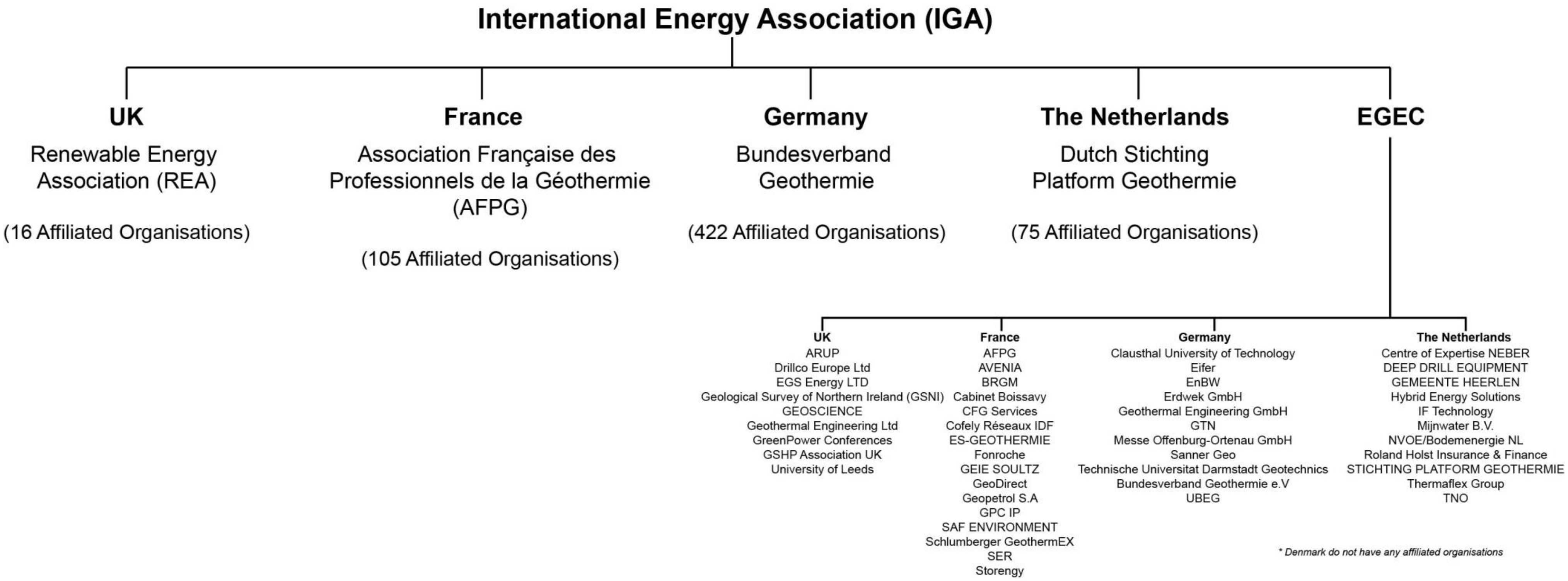


Figure 3-19: The structure and current paid members of the IGA and European Geothermal Energy Council as of March 2016 (EGEC, 2016; IGA, 2016).

3.10 Non-Technical Assessment – Country Specific

3.10.1 France

3.10.1.1 Policies & Licensing

France has determined that 23% of their final energy consumption be from renewable energies by 2020; this equates to an additional 232,600 kWh consumption of renewable energies. Of this 23%, 50% of additional energy production is to be provided by renewable heat, whilst the remainder is to be provided by renewable electricity (Lopez et al., 2010; Vernier et al., 2015). Policies to incentivise the uptake of deep geothermal heat projects have been proposed and implemented by the French Government to help achieve these targets. These include the following (Lopez et al., 2010; Vernier et al., 2015):

- Implementing a reduced VAT rate if the energy company in question obtains 60% of its energy from "clean" sources (includes geothermal).
- Implementation of a Renewable Heating and Cooling Fund; a financial incentive for commercial/office buildings and agriculture/industry whereby funds make heat prices for geothermal-derived projects 5% less than conventional heat. Established in 2009, the scheme should ultimately distribute €1.2 billion to all renewable technologies in the period 2009-2013.
- A subsidy of up to 30% of total investment is available if eligible.
- A Geological Risk Insurance Scheme. Deep geothermal schemes are insured up to a total of €4.2m, whilst shallow projects are protected up to €115k. This kind of risk management scheme has been in place since the early 1980's. At that time the cost of a failed project would have to be covered by the public as it was mostly public bodies that were attempting to exploit the available geothermal resource. The risk to the public was deemed unacceptable and as such a risk insurance system was introduced. Both short term and long term risk insurance has been put in place. In the short term, the feasibility of a scheme is assessed based on a comprehensive technical, economic and financial evaluation. The temperature and fluid flow rates are estimated and the expected financial success of the project is based on this value. For a 1.5% payment of the insured cost, compensation of up to 90% of the eligible cost can be recovered if the first well fails. The long term performance of the system is also insured to cover potential scaling, corrosion and ultimately permeability reducing effects. These work on timescales of up to 25 years and must be independently verified by an expert. Both insurance schemes are backed by state

funding and the state-funded French Environment and Energy Management Agency (ADEME).

There are also several regulatory changes detailed within the NREAP for France that target thermal renovation and thermal standards in new-build properties.

Due to the zone of pressure drawdown being well defined within the doublet systems employed within the Paris Basin, it has been easy for authorities to define ‘exploitation zones’. Lopez et al. (2010) describes the management of the aquifer in the definition of ‘exploitation zones’ as being of “crucial importance”, as the Dogger Aquifer will ultimately be exhausted and breakthrough of cooled brines will occur eventually. Proper understanding of these issues allows the aquifer to be exploited in the most efficient manner. Licensing through ‘exploitation zones’ aims to enhance efficiency and reduce conflict between different users.

Despite the growing deep geothermal capacity in France, Vernier et al. (2015) state the 2020 target for geothermal district heating are unlikely to be met.

3.10.2 UK

3.10.2.1 Policies & Licensing

Batchelor et al. (2015) state UK geothermal policy is driven primarily by Climate Change policy; our need to improve uptake of renewable energies are driven by our need to reduce our production of CO_2. The current DECC funding opportunities that could be applied to the geothermal (heat only) industry is detailed below.

- Heat Networks Delivery Fund (HNDF); a decarbonisation strategy that is currently on its 5th round of funding calls. The HNDF does not have to rely on heat generated from geothermal. It can be from a CHP, water source heat pump (not specifically geothermal) or waste heat from industry. The HNDF document indicates there are approximately 2000 heat networks within the UK, supplying heat to 21,000 homes and 1700 commercial/public buildings. DECC estimates that by 2030, 14% of UK heat demand could be provided by heat networks, increasing to 43% in 2050. The Heat Networks Delivery Unit (HNDU) only supports heat network projects - no derivatives. The applicant must match fund at least 33% of the estimated eligible external costs of feasibility studies. The current round focuses project specific investigations and it must come from a Local Authority.

- Feed-In-Tariff - Renewable Heat Incentives (RHI): The domestic RHI does not consider deep geothermal and as such only the non-domestic RHI will be considered here. The non-domestic RHI is designed for commercial, industrial, public sector and not for profit organisations, and also heat networks. Deep geothermal is amongst the heat technologies that are covered. Payments are made over 20 years and are based on heat output. DECC initially supported deep geothermal under the large Ground Source Heat Pump (GSHP) tariff, but found that it did not stimulate uptake as deep geothermal is so different from GSHP. Inclusion of a separate deep geothermal tariff was implemented; now there is non-domestic deep geothermal support of 5.14p kWh^{-1} as of 2016 (Ofgem, 2016) for wells obtaining heat from a depth of <500 m.
- The Renewable Heat Incentive (RHI) is currently suspended due to a budget overspend. New applications are not currently being sought.
- Community Energy Strategy: The UK Community Energy Strategy, first published in January 2014, wants to reduce the number of barriers that hinder small community energy projects. It has three key benefits:
    - "Maintain energy security and tackle climate change.
    - Save money on energy bills.
    - Bring wider social and economic benefits."

  A drive to devolve the centralised energy system to provide distribution on a local scale instead is how the scheme is intended to operate. Local communities will have a say in their energy source and also potentially have a stake in their energy generation and distribution. In addition there is the potential for local communities to manage and reduce their energy demand.

Renewable Obligation Certificates (ROCs) are not considered here as this details support for electricity generation only and is concerned with suppliers obtaining more electricity from renewable sources. As a point of interest, the UK NREAP has allocated two ROCs for geothermal. The UK NREAP does not provide an estimate of the contribution deep geothermal may have on 2020 targets for heating and cooling, stating "n/a" for the period 2010-2020.

The licensing of deep geothermal within the UK comes under water abstraction legislation. The Department of Energy & Climate Change (DECC) have provided guidance on geothermal water abstraction under their Deep Geothermal Energy Regulation. To abstract water from the subsurface, three environmental permissions are required.

- A Groundwater Investigation Consent (GIC). A pump test may not be required if the well is sufficiently deep and a conceptual model + desk study can be provided.
- Abstraction License (much like in the water industry).
- If water is to be discharged to the surface, an environmental permit is required.

If heat is lost during pumping of water because of abstraction elsewhere, it is not considered. It is up to the licensee to determine whether the abstraction rates are suitable for their scheme with regards heat loss. They will only assess the risk to other abstractors of water which provides little protection to those implementing a geothermal scheme.

Consultation during 2014 was undertaken to assess simplification of underground access rights to reduce the barriers to geothermal development by businesses. ‘Voluntary payments’ to communities made by those wishing to develop the geothermal resource would be required. It has yet to be determined if this change in stance has had a positive or negative impact on geothermal uptake.

3.10.3 Germany

3.10.3.1 Policies & Licensing

The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) set time-based targets to increase the amount of renewables used in final energy consumption within Germany. By 2020 renewables are to form 18% of the total energy consumption, increasing to 60% by 2050 (Weber et al., 2015). As of 2015 geothermal systems accounted for 0.075% of renewable energy consumption. Incentives and policies to support renewable uptake are as follows:

- Under the Renewable Energy Sources Act 2012 (EEG) a feed-in tariff is offered on new geothermal projects. Currently geothermal electricity is subsidised by €0.25 per kWh. An additional €0.05 per kWh for geothermal derived from petrothermal (EGS) methods was available but later abolished. A subsidy for geothermal heat is not currently available under the EEG feed-in tariff. One of the most important aspects of the EEG is that grid operators in Germany are obliged to purchase energy created from renewable energy sources over traditional fossil fuel energy sources. The prioritisation of sourcing energy from renewable sources is hoped to further drive industry investment into renewables.
- Renewable Energies Heat Act 2009 (EEWärmeG) stipulates new buildings must obtain part of their heat supply from renewable sources. By 2020 14% of heat

supply is proposed to come from renewable resources and funding up to €50,000 is available. More recently, EEWärmeG is being implemented in existing public buildings that are undergoing renovation works. The BMU also hopes to not only reduce the costs associated with renewable power generation, but also increase the pressure on industry to create innovative solutions to renewable energy power production. The inclusion of enhanced tariffs for energy produced from renewable sources also serves to aid the process.

- Geothermal risk is taken up by Munich Re insurers and the BMU. They will finance projects for up to 80% of the drilling costs and provide full risk coverage for wells over 400 m (Weber et al., 2015).
- A Geothermal Information System (GeotIS) has been developed and provides members of the public with information on geothermal developments across Germany. GeotIS was developed by Leibniz Institute for Applied Geophysics (LIAG) in Hannover (Agemar et al., 2014a; Weber et al., 2015).

Licensing of deep geothermal within Germany is overseen by the Federal Mining Act. Underlying this regulation are building permits and regulations under the Water Act, but the overarching binding license is based on mining and mineral extraction.

3.10.4 The Netherlands

3.10.4.1 Policies & Licensing

Initial geothermal development in the Netherlands did not provide an adequate incentive to invest into schemes. Until gas prices began to rise it wasn't seen as feasible to place money in an untrusted and unproven technology. Attitudes changed as gas prices began to rise in the early 2000's. Licensing of geothermal within the Netherlands was developed using the Mining Act; a piece of legal framework developed for the oil and gas industry that covers wells >500 m depth. An exploration license is required in the first instance prior to any drilling. A production license is then required to operate the scheme. Currently there are only two wells that have a production license (out of a total of nine). The legislation is adequate to a point, but when dissolved methane gas began being extracted within two wells, the legislation required further refinement. The advantage of licensing in a similar manner to the oil and gas industry is that the license is operated by a sole user or consortium of users; there is no competition from others and the resource cannot be depleted by others. Further issues with the licensing of geothermal exploration wells are addressed *ad hoc*, such that a 'light' exploration license was suggested to allow for desk-based study to be undertaken prior to full exploration (drilling) licenses being granted. The use of block licenses allows additional time to determine if the scheme is worth further investigation.

Current policy and subsidies within the Netherlands are presented below.

- Stimulation Sustainable Energy Plus (SDE+): covers the gap between the cost of producing the energy through sustainable sources and the cost of producing that same energy using conventional sources. This would ideally make energy derived from deep geothermal heat the same price as heating using traditional gas. The incentive is part-funded by consumers. The system relies on a fixed base rate for producing the energy and a correction rate for producing the same energy using conventional means. Subtracting the former from the latter gives the subsidy rate. Applications to the subsidy are time limited with those applying facing competition with one another. Technologies with a low base rate are in the first funding round (geothermal falls into this round), with subsequent rounds seeing the base rate increase. There is an issue with the funding being exhausted in later funding rounds because of its popularity, out-pricing more expensive technologies. A maximum subsidy is in place to stop over subsidisation. A drawback of the scheme is that it can only be applied for once the well is up and running; the costs of drilling and building the scheme are not covered. In addition, Combined Heat and Power (CHP) geothermal systems are not currently supported given their high base rate cost.
- Guarantee Scheme (SEI Aardwärmte): as part of the Netherlands NREAP the Dutch Government created a risk insurance scheme that works partly like a subsidy as it covers wells that do not perform satisfactorily. The SEI Aardwärmte scheme is one that does not necessarily have to be taken up by investors as it is up to individuals to manage the risk how they see fit. The scheme is not guaranteed long-term as the Government will only run it if there are no other private insurance outfits in the market.

The Platform Geothermie (Geothermal Platform) is a group of 80 Government organisations, academic institutions and industry (including energy companies, financial and technical service providers and current license holders) whose aim is to develop geothermal energy within the Netherlands. Platform Geothermie is currently a member of the European GeoDH and also the International Geothermal Association (IGA).

3.10.5 Denmark

3.10.5.1 Policies & Licensing

The generation of energy in Denmark was once dominated by imports of oil and gas. An option to produce energy by nuclear means was strongly opposed and more recently removed completely from their long term energy plans. Much of the Danish Energy Agreement legislation focuses on improving energy efficiency and energy savings which does indirectly have an effect on uptake of renewable energy. It is planned that by 2050 all energy will be produced without dependence on fossil fuels (International Energy Agency, 2011a). An approximate contribution of 0.07% from geothermal heat pumps is planned to contribute towards final heating and cooling demand in 2020.

Geothermal licenses are provided under the Danish Subsoil Act, administered by the Danish Energy Agency (Røgen et al., 2015). The Danish NREAP and Danish Energy Agency (2012a) discuss the £3.7 billion Danish Energy Agreement, detailing the following incentives and policies to install geothermal systems.

- Subsidies amounting to £4.4m (DKK 42m) for scrapping of oil fired boilers and replacing with geothermal heat pumps (and other alternatives).
- A £3.7m (DKK 35m) fund was allocated for developing district heating (including geothermal) in 2013.
- High taxes on fossil fuels, pushing developers into choosing renewable energy sources.

Currently there are 12 exploration and production licenses for geothermal within Denmark.

In November 2015, it was announced that Danish Geothermal District Heating was to close, citing the “difficult framework of geothermal energy in Denmark and the lack of political support”. The 2016 national budget removed the financing of the national guarantee fund, and as such no formal guarantee is in force within Denmark.

3.10.6 Summary

Table 3-7 broadly summarises which target countries have incentives, a legal framework and licensing system in place (where data is available).

Table 3-7: Summary of available incentives by country. [1]pre-build and build phase incentives are funds and grants that can be used in the R&D and exploration of geothermal and/or help with installation of surface infrastructure. It includes access to EU funding streams. [2]Building Regulation covers legislation that includes a requirement for both existing and new developments to source a proportion of energy from renewable resources. It also includes legislation that improves efficiency and insulation of properties, whether new build or retrofitted specifically for heat networks. [3]post-build incentives are Feed-In-Tariffs that can be used on heat sold to the market.

	Incentives ([1]pre-build, build phase)	[2]Building Regulation	Incentives ([3]post-build)	Risk Insurance	Licensing
UK	Y	-	Y	N	Y
Germany	Y	Y	Y	Y	Y
The Netherlands	Y	-	Y	Y	Y
France	Y	Y	Y	Y	Y
Denmark	Y	Y	-	N	Y

3.11 Discussion

3.11.1 Technical Barriers

3.11.1.1 Aquifer Properties

Presented in Table 3-8 are the aquifer parameters obtained for tested and/or producing geothermal aquifers in the target countries. It should be noted the same level of data may not be available for every country; cells annotated with "-" denote such gaps in the data. Comparing values for the shared Permian-Triassic aquifers indicate there are variations but they all sit within a range that is acceptable; the unit has still been exploited regardless.

Cut-off values for suitable aquifers vary by author. The original geothermal review for the UK (Downing and Gray, 1986a) state flow rates of 90-180 $m^3\ hr^{-1}$ (25-50 $L\ s^{-1}$), temperatures of 40°C and an intrinsic transmissivity of 5-10 D m are necessary for a viable resource (they do also concede that future resources may have a lower cut-off temperature of 20°C). More recently the minewater project at Heerlen, Netherlands pumps water from disused flooded mines at a depth of 700 m depth at a rate of 80 $m^3\ hr^{-1}$ and temperature of 28°C (Verhoeven et al., 2014). Whilst the flow at Heerlen is through mine conduits and not necessarily comparable to the style of flow in deep geothermal aquifer systems, the flow is still of a comparable value to that given by Downing and Gray (1986a). It indicates that there is still a resource despite the lower temperature. As more developments utilise these lower temperature resources, or start to exploit them in conjunction with other renewable resources (for instance, using biomass boilers to boost the water temperature), lesser quality aquifers can begin to be exploited. This widens the volume of resource available; the initial geological uncertainty still remains, but the amount of tolerance in having useable aquifer parameters increases.

It can be said that at this level of assessment the aquifer properties do not necessarily form a technical barrier to uptake in the target country. These barriers can be overcome through engineering and aquifer management, albeit it at a cost. However, assessing these properties alone miss the bigger picture. The aquifer properties may be such that a large resource and reserve exist. However, if in that particular location there is no heat demand, it becomes redundant.

Table 3-8: Summary of aquifer/reservoir properties from all countries

France											
Aquifer	Sediment Type	Flow Type	Permeability (mD)	Porosity (%)	Flow Rate (m^3 hr^{-1})	Depth to Aquifer (m)	Thickness (m)	Temperature (°C)	Temperature Gradient (°C km^{-1})	Heat (MW_t)	Resource
Dogger Formation	Carbonates	Fracture+Pore	2000-20000	15	100-300	1500-2000	20 (productive)	55-80	3.5	-	
Albian	-	-	-	-	200	650	-	28	-	1.3-5.4	
Neocomian	-	-	-	-	-	900	-	34	-	-	
UK											
Aquifer	Sediment Type	Flow Type	Permeability (mD)	Porosity (%)	Flow Rate (m^3 hr^{-1})	Depth to Aquifer (m)	Thickness (m)	Temperature (°C)	Temperature Gradient (°C km^{-1})	Heat (MW_t)	Resource
Sherwood Sandstone Gp	Sandstone	Pore	200	10	43	1800	35	76	38	2	
Germany											
Aquifer	Sediment Type	Flow Type	Permeability (mD)	Porosity (%)	Flow Rate (m^3 hr^{-1})	Depth to Aquifer (m)	Thickness (m)	Temperature (°C)	Temperature Gradient (°C km^{-1})	Heat (MW_t)	Resource
Valendis Sst	Sandstone	-						50	33		0.11 EJ
Bentheimer Sst	Sandstone	-						54	33		0.28 EJ
Aalen	Sandstone	-						43	33		80.83 EJ
Lias & Rhät	Sandstone	Pore with minor fracture	200-800	22	950-3024		57	38	33		102.87 EJ
Schilfsandstein	Sandstone	-	300-1500	20-34				48	33		37.88 EJ
Buntsandstein	Sandstone	-		10				49	33		70.88 EJ
Netherlands											
Aquifer	Sediment Type	Flow Type	Permeability (mD)	Porosity (%)	Flow Rate (m^3 hr^{-1})	Depth to Aquifer (m)	Thickness (m)	Temperature (°C)	Temperature Gradient (°C km^{-1})	Heat (MW_t)	Resource
Permian Rotliegend Sandstones	Sandstone		30-600	11-25		2000-4500	10-200	max. >100	31		
Lower Triassic Sandstones	Sandstone		variable	variable		2000-4000	25-300	max. >100	31		
	Sandstone		variable	variable		2000-3500	80	max. >100	31		
	Sandstone		variable	variable		300->5000	0-50	max. >100	31		
Lower Cretaceous Sandstones	Sandstone		max. 3000	15-30		700-2500	max. 250		31		
	Sandstone		220-500	15-20		800-1800	3-65		31		
	Sandstone		1-30	15-22		1800-2100	10-200		31		
Tertiary	Sands		max. 600			100-1150	0-135		31		
			50->200	30-35		<835	variable		31		
Denmark							gross				
Aquifer	Sediment Type	Flow Type	Permeability (mD)	Porosity (%)	Flow Rate (m^3 hr^{-1})	Depth to Aquifer (m)	Thickness (m)	Temperature (°C)	Temperature Gradient (°C km^{-1})	Heat (MW_t)	Resource
Bunter	Sandstone	-							22-28		
Gassum	Sandstone	-							22-28		
Skagerrak	Sandstone	-							22-28		
Haldager	Sandstone	-		15-30			30-175		22-28		
Frederikshavn	Sandstone	-							22-28		

3.11.1.2 Heat Demand

Geothermal resources exist for every nation on Earth because the temperature increases beneath the Earth's surface, and while the rate of temperature increase as a function of depth varies from place to place, this simply means that the accessibility and quality of the geothermal resources also varies spatially. The limiting factor on developing a resource then becomes the heat demand; without a heat demand the resource will not be developed. If the heat demand is large, the cost of retrieving the available reserve must then balance with the heat the system can supply and the issue becomes one of economics and geological limitations (lack of reservoir, poor quality aquifer properties, low thermal gradient etc).

Heat can be moved through insulated pipe networks at a thermal cost of 0.5-1.0°C per kilometre of pipe (Cofely GDF-Suez, 2012, 2015). The economic cost is high; approximately £1m per kilometre of pipe in an urban UK area (Williams, 2014). It should be noted the value of £1m per kilometre of pipe is specific to the UK and is also specific at the time of quotation. The price will naturally fluctuate, but will also decrease if the heat network is installed during a new-build project as opposed to retrofitting of existing buildings. Engineering an efficient heat network is possible based on the current technology available. The economic cost of doing so becomes the caveat given the variation in pricing such a system.

Geothermal resources in all countries assessed have been used for either one or both of the following purposes:

- District Heating and cooling.
- Greenhouses/agriculture.

Both of these methods of utilisation can be retrofitted to existing infrastructure to take heat from geothermal sources.

Within England heat density has been mapped and is presented as Total Heat Density in Figure 3-20. In addition the location of Mesozoic sedimentary basins (and therefore geothermal resource), as determined by Barker et al. (2000), has been superimposed onto Figure 3-20 to show where they may be crossover between location of resource and end user. It is these locations that form the most viable target for developing a geothermal resource (if we assume the geothermal resource is associated with Mesozoic basins only). The area around Southampton shows a moderate Total Heat Demand; other areas showing similar Total Heat Demand coincide with Mesozoic basins and could form a feasible location for deep geothermal exploitation for district heating and cooling. In Denmark geothermal resources have been developed around the heat demand for housing/commercial properties in the form of heat networks. The Netherlands have also targeted these areas along with existing commercial greenhouse projects, as have Germany and France.

Heat demand is not considered a technical barrier within the UK in the first instance as there are many end-users located across the UK who could benefit from a district heat network. They are situated in places where heat demand overlaps an area that is reported to be a good quality location for deep geothermal exploitation (Figure 3-20). It should also be said that even if the best resource did not match with a particularly high heat demand, there is nothing to stop new developments being sited in areas that could be served by geothermal heat. Such high heat load developments include hospitals, schools, leisure/shopping centres and the aforementioned greenhouses. A secondary effect of heat demand is the potential economic cost to installing a heat network; it is this effect that is the barrier.

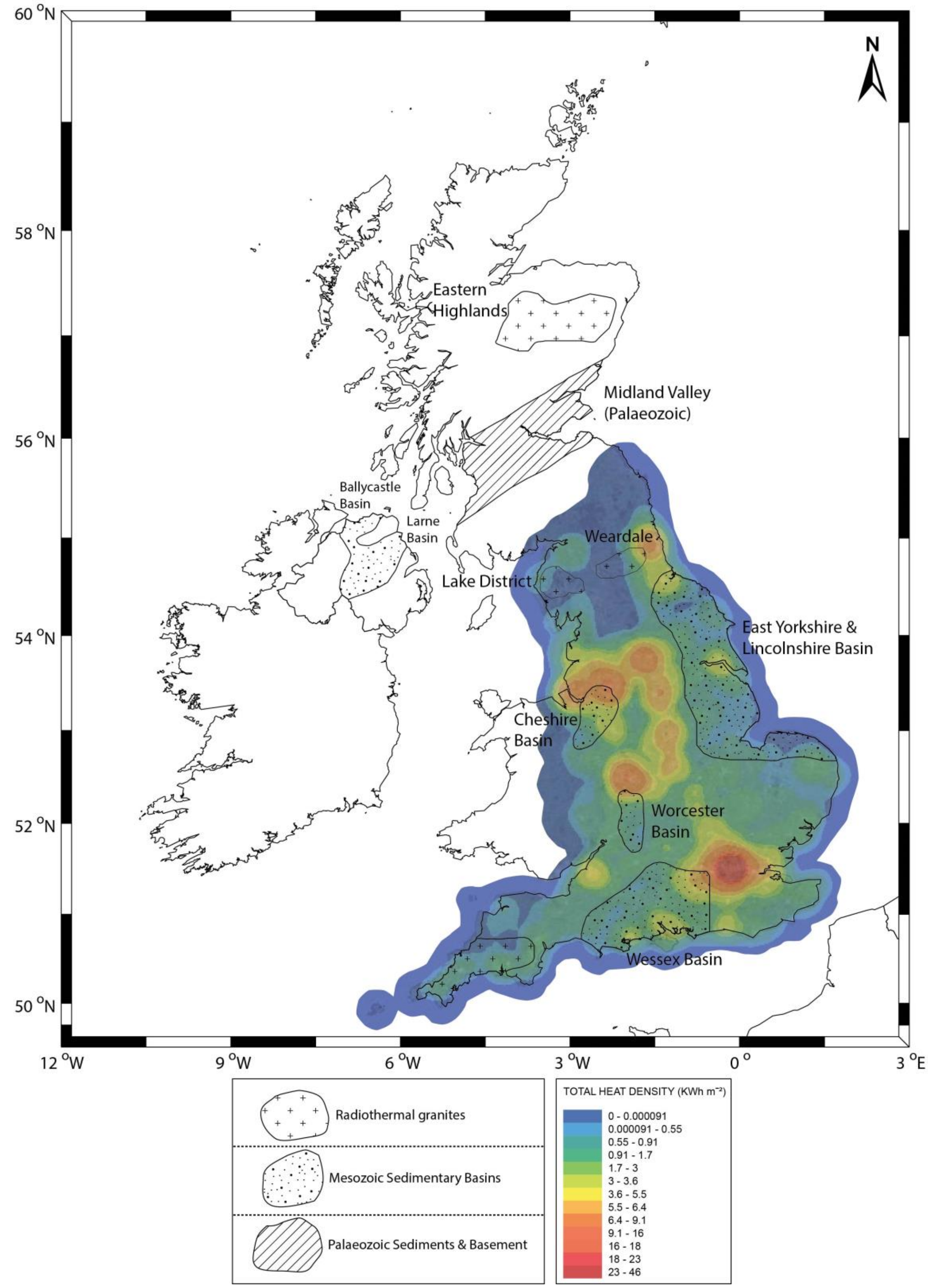


Figure 3-20: Total Heat Density (DECC, 2016) and Mesozoic Basin location (Barker et al., 2000). The area around Southampton shows a moderate Total Heat Density and indicates the best locations for exploiting a known geothermal resource associated with Mesozoic basins.

3.11.1.3 Mechanical Barriers: Well Lifespan and Failure Rates

Data has been presented for each country regarding the well lifespan and well failure rate where available. Other mechanical failure mechanisms during geothermal well drilling have been defined by Huenges (2010) These mechanisms can form potential barriers during drilling of geothermal boreholes. Some of these issues (such as borehole breakouts squeezing/swelling formations) should be identified during the preliminary characterisation of the resource (if done thoroughly enough). Some of these will be difficult to anticipate, such as unexpected geology/fracture zones and fluid chemistry. These mechanical issues can go on to cause a reduced well lifespan, poor well integrity and ultimately high well failure rates. Of the countries assessed, the Paris Basin wells appear to suffer from large amounts of scaling and/or corrosion due to the nature of the geothermal fluids. All three geothermal installations in Denmark have begun to suffer from corrosion and injection issues also. The steel casing in Denmark is designed specific to the extracted fluid chemistry. The plant at Thisted has a thickness of 3 mm and corrodes at a rate of 0.06 mm yr^{-1}. The plant at Copenhagen has a casing thickness of 5 mm and corrodes at a rate of 0.2 mm yr^{-1}, giving a maximum lifespan of 25-50 years (Røgen et al., 2015). Injection well pressures have suffered in Denmark also and frequent soft acidisation is required. The time required for these shut-downs is not reported. The well drilled at Groß Schönebeck, Germany, suffered from salt creep during drilling which blocked the well. However, the problem was easily overcome with some adjustments to mud weight and casing design and the well was still completed ahead of schedule (Huenges, 2010). Despite these mechanical issues, some installations in France have been producing for 46 years (Lopez et al., 2010), 28 years in the UK (Geothermal District Heating (GEODH), 2016), 32 years in the Denmark (Røgen et al., 2015), 13 years in Germany (Agemar et al., 2014a) and 9 years in the Netherlands (Kramers et al., 2012).

All countries have experienced well failures at some point. The recovery from these failures differs, however. Whilst the failed well (Asten-2) in the Netherlands caused the industry to stagnate, changes in oil and gas prices drove it back up the agenda (van Heekeren and Bakema, 2015). Conversely it appears successful installations don't always pave the way for further resource exploitation, as seen at Southampton. It took until 2004 for further geothermal wells to be drilled in the UK (Manning et al., 2007; Younger and Manning, 2010). Since then the well drilled at Science Central, Newcastle-Upon-Tyne in 2011 could be classed as a failure (but without clear understanding of the failure mechanism in the public domain). Whether Science Central has further hindered resource uptake is unclear. Plans for deep geothermal at Stoke-On-Trent are moving forward, the limiting factor being based on economics.

3.11.2 Non-technical barriers

3.11.2.1 Government Policy

Each country assessed has developed legislation and incentives/funds to promote the development of geothermal resources. The focus of these incentives shows some variation in that Denmark has focused on energy efficiency whilst France and Germany attempt to engage the construction industry by writing in legislation forcing developers to source a proportion of their energy from renewable sources. District heating networks are expensive to retrofit, but for new build projects are cheaper. In addition, France has funds and incentives to better insulate homes and businesses.

The timing that an incentive can be applied is a limitation on geothermal resource development. Feed-In-Tariffs can only be applied once the system is proven. However, as will be discussed in Section 3.11.2.2 a large proportion of capital costs are expended early within the development and construction of a geothermal installation (Figure 3-21 and 3-22). If the installation does not then produce as much energy as was anticipated, the FIT will return less income. Another limitation with certain funding types is there are often caveats on the funding streams that can be applied. Typically only one type of funding can be used. If used in conjunction with something like a FIT, there will be an expected payback. If a system generates profit there will also be a repayment required. Whilst repayment may not be an issue where projects are developed to generate energy for specific construction projects (public buildings, proof-of-concept installations), private investors may be deterred from putting money into a system that can’t ultimately generate revenue. It is understandable as to why revenue generation is kept under control, but the manner in which it is currently promoted may form more of a barrier than an incentive.

The effect of removing incentives and funding also has a detrimental effect, not only because of the obvious removal of funds. The Northern Ireland Renewable Heat Incentive is currently suspended due to a large budget overspend. The overspend will be reviewed but it currently forms a barrier to the uptake of resources. It introduces mistrust into the funding streams and could potentially deter investors in applying.

3.11.2.2 Risk Insurance

Lopez et al. (2010) state three reasons as to why geothermal development within the Paris Basin has been so successful. Two reasons have already been highlighted, namely the presence of a hot water reservoir with correspondingly suitable flow rate and temperature, and also the presence of a heat demand (Paris and the surrounding suburbs). The third reason as to why geothermal development within the Paris Basin has been so successful is the availability of an insurance scheme to protect against failed wells. The availability of an insurance scheme is weighted such that it is equally important as having an achievable technical resource. The UK and Denmark do not have a form of risk insurance in place to protect investors from failed projects. Within Denmark there were plans to provide a guarantee scheme, the funding for which has recently been cut out of the 2016 budget. The funding cut has been a sizeable blow to geothermal development within Denmark and has led to the closure of the Danish Geothermal District Heating Company, announced to take effect in February 2016. The Danish Geothermal District Heating Company has been involved in the building and operation of the three deep geothermal installations in the country. Currently it is not known what the fate of these developments will be in the future.

Risk insurance in Germany is not only served by a state-owned bank (KfW banking group), but there is also a competitive market for risk insurance (Munich Re Group provided the first risk insurance for the Unterhaching project in the Molasse Basin). The industry has grown large enough to be self-supporting. The Netherlands still offer a Government backed risk insurance with additional financing options to encourage new geothermal installations. It is hoped that ultimately private insurers will take over the risk insurance and financing market. France is the only country to offer both short and long-term risk insurance for geothermal projects. The corresponding uptake of geothermal in these countries is much larger than in the UK and Denmark.

Attracting investment, given the technical barriers described above, becomes a major hindrance. Figure 3-1 showed the levelised cost of geothermal electricity production as being partly comparable to conventional generation. However, geothermal heat is unlikely to show the same relationship; a unit of heat is worth less than a unit of electricity. According to Arup (2011) 60-70% of the total cost of a geothermal scheme are spent during the exploration and drilling phase. Figure 3-22 (AECOM, 2013) displays the percentage cost split between the start-up of a geothermal project and onshore wind project to the point of production versus other costs (taken from the German FIT review). The risk of failure at the exploration phase is still moderately high (Figure 3-21), and at least 50% of the total cost is required to get to this point (Figure 3-22). Without risk insurance a deep geothermal heat project becomes untenable for many. The risk insurance / guarantee schemes currently in place allow investors to procure step-by-step security throughout the development of a resource making investment much more palatable.

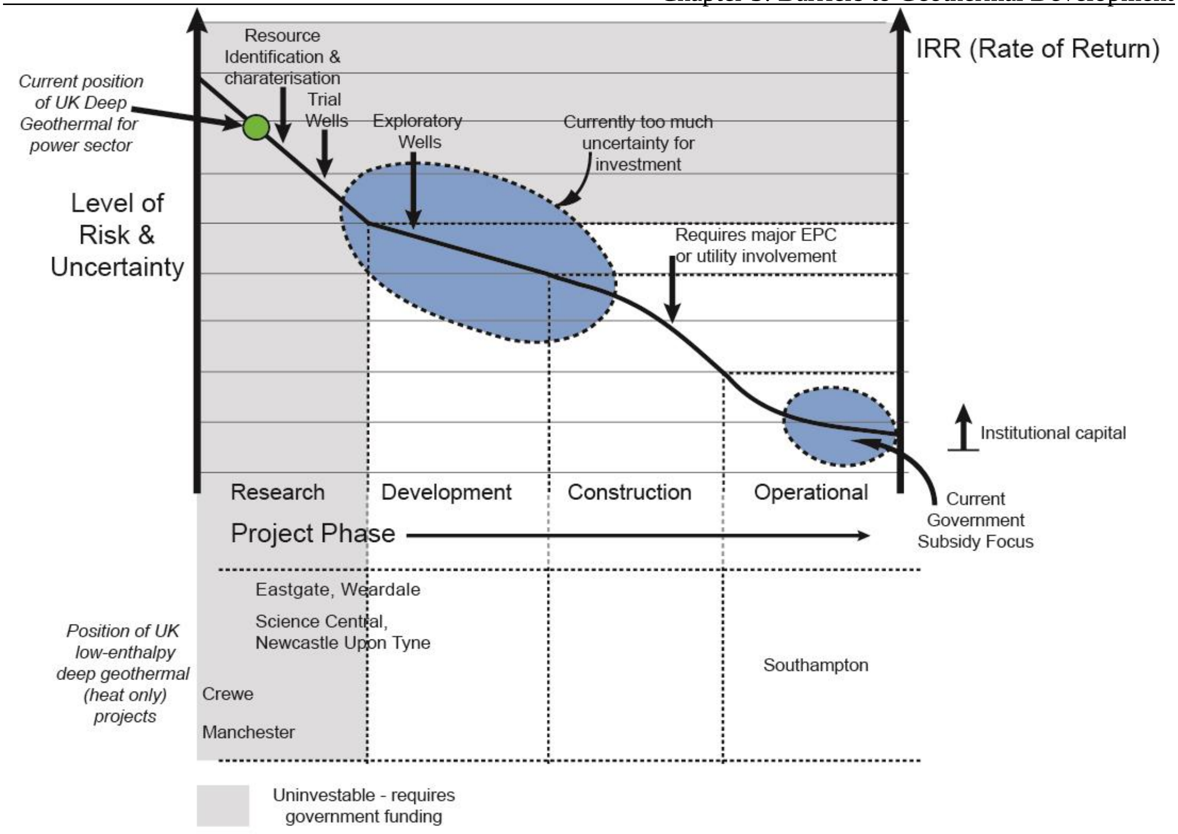


Figure 3-21: Investor view of risk in geothermal resource exploitation (Atkins, 2013).

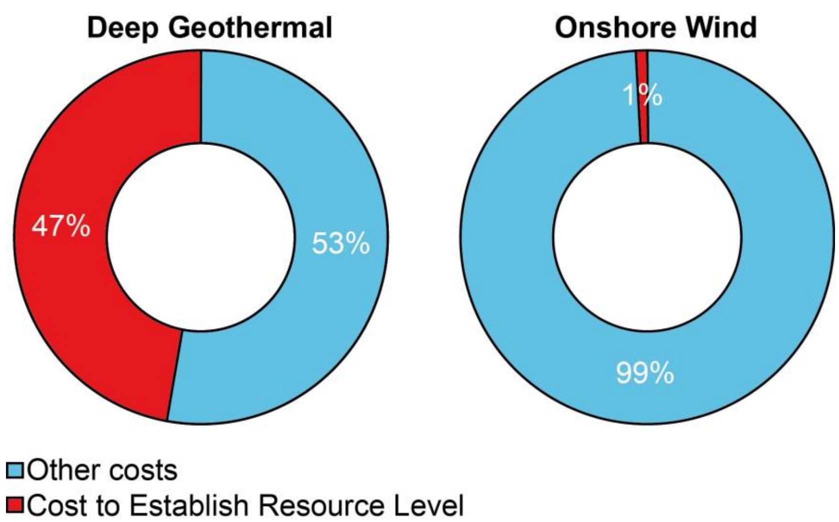


Figure 3-22: Percentage cost split between establishing a resource and other incurred costs (AECOM, 2013)

The report produced by AECOM (2013) indicated that, within Scotland at least, a Government-backed risk insurance for exploration is a possibility. The crux of any Government-backed insurance lies in whether any risk guarantee would constitute State Aid. The Scottish Government’s State Aid Unit has reviewed the terms of what would be seen as State Aid and indicated that in the eyes of the EU, it would be possible for the Scottish Government to provide exploration risk insurance in the form of a guarantee for up to 80% of the costs. However, despite it being technically possible, the money would have to be put aside in the relevant budget to the potential detriment of other renewable technologies. As AECOM (2013) assert, it then becomes a matter of choice on the part of the Scottish Government.

3.11.2.3 Licensing

Geothermal resources are licensed in all countries assessed. However, the suitability of the licensing framework within the UK is arguably not fit for purpose. The resource is only viewed from the aspect of water abstraction; stored heat is not considered. Whilst licenses will be refused if they threaten the water supply licensed by another user in the vicinity there are no limits on the removal of heat. There are no regulations stopping another user drilling and exploiting a similar thermal reserve. Currently shallow geothermal resource exploitation could potentially suffer greatly from the lack of regulation. The installation of shallow ground source heat pumps can be done by home-owners and businesses on a small scale. As more people install such systems, interference between boreholes will be seen. The potential for borehole interference is arguably a bigger problem if a deep geothermal reserve has been developed – the loss of revenue from a cooler resource has a bigger financial impact.

Licensing systems in comparative countries treat geothermal in a similar manner to a mineral resource, and as such the heat is a licensed commodity. Mineral resource frameworks place greater security for any developer wishing to “mine” the heat. In particular the Netherlands license geothermal in blocks similar to that used in the oil and gas industry. The license holder of the block will be the sole developer of the heat contained within that block. Determining two types of license (an exploration license and a production license) further aids geothermal uptake as it can reduce costs.

Investors looking to develop a geothermal resource in the UK will look at the security of such resources. Deep water extraction through boreholes is a limited occurrence (most water abstractions are at shallower depths), but this does not rule out future licenses based on the potential for shale-gas developments at these depths. Water abstraction licenses would protect the developer in this instance but the potential for heat loss is not regulated. The lack of clarity in licensing is considered a barrier in the uptake of geothermal resources in the UK for the reasons described above.

3.11.3 General Discussion

The UK is a country built on hydrocarbons. During the 1960's large scale investment was made to connect all houses and businesses up to accept newly discovered North Sea Gas. Prior to the discovery of North Sea Gas, municipal Town Gas supplies formed a proportion of the energy consumed by homeowners. These were run on a Local Authority scale. In addition, coal fires were a staple of heating for most houses across the country. The oil crisis began to change our energy outlook; in 1970 approximately 96% of UK energy consumption was provided by fossil fuels (DECC, 2015). The EU was in much the same situation and as a result there were efforts to diversify energy portfolios. France invested most of their resources into nuclear energy (to the detriment of other renewable resources), whilst Denmark were committed to a long term investment in increasing the energy efficiency of buildings through building regulation (Danish Energy Agency, 2012b; Planete Energies, 2015). In terms of energy generation, the focus of resources was on combined heat and power, municipal heat networks, re-organisation of the energy grid, increased usage of North Sea gas and large investment into research in green technologies. Taxes on hydrocarbon-derived CO_2 emissions help finance energy policy in Denmark (Danish Energy Agency, 2012b). Germany also focused on diversifying their energy policy but again the initial focus was on nuclear. The investment into renewable energy has only taken shape more recently. The effects of the Fukushima nuclear incident caused Germany to look again at their nuclear energy policy and shifted policy towards greener energy sources (Deutsche Bank Research, 2014). The Netherlands invested heavily in a gas network to distribute the newly discovered Groningen gas field, and incentivised the conversion to gas. Energy saving measures were not promoted until after the 1973 and 1979 oil crises. Since then incentives have been provided to improve the efficiency and insulation of existing domestic and commercial properties, and also new-build projects (United Nations, 1999). From the above description we can see all countries were effectively sealed into the same situation with the repercussions of actions taken at that time still being felt today. Denmark appears to have benefitted overall as they had a clear long term plan that has been implemented for the last 46 years, regardless of changes in Government, and is reflected in their current installed renewable power capacity (40% of electricity consumption is from renewables). It is more recent changes in policy that have caused the growth in renewable technology across Europe. The policy changes have been driven by social pressures in the 1960's and 1970's, climate awareness and CO_2 reductions (United Nations, 1997), investment into R&D of renewable technologies, and ultimately are related to increases in conventional fuel prices. The latter point is illustrated perfectly by the Netherlands return to geothermal; it was driven by the increased cost in oil and gas prices despite large amounts of uncertainty in geothermal technology (van Heekeren and Bakema, 2015).

3.12 Conclusions

The uptake of geothermal resources relies on several factors, namely:

- Favourable geological conditions.
- Heat demand and end user/defined end use of heat.
- Financial backing/support.
- Risk Insurance.
- Licensing framework.

The interaction of these factors ultimately determines whether a geothermal scheme is viable, although some of these factors are more important than others.

The UK is underlain by strata that are geologically comparable to strata seen in Germany, France, the Netherlands and Denmark. The geological and mechanical (technical) barriers to geothermal resource exploitation are similar across these areas; flow rates, temperature, depth to reservoir, rock type and heat demand are broadly similar. There are both inter- and intra-continental heterogeneities that will affect the overall performance of a geothermal installation, and the overall resource value will be site specific. In addition the drilling, installation and maintenance of a geothermal system have the same technical barriers across all countries assessed. These barriers therefore are not considered to be specific to the UK and cannot, on their own, be seen as the reason for an under-developed deep geothermal resource-base. To overcome technical barriers in the development of geothermal resources, non-technical barriers become the limiting factor. The interplay between Government policy, risk management and licensing form the three major barriers to country-specific geothermal uptake. Risk insurance forms a major incentive in the uptake of geothermal resources. The lack of insurance within the UK, when combined with Government policy and inappropriate licensing, makes it incredibly difficult for any investment to be made. These have, on the whole, been addressed to a greater extent in Germany, France, the Netherlands and Denmark and have allowed a greater geothermal resource to be developed as a consequence. The UK has a strong backing from academic and industry partners, but still struggles to gain the support it requires to further develop resources.

One criticism of the UK’s organisational structure is lack of a clear UK-geothermal specific steering group. Such organisations seen in other countries drive forward the geothermal agenda in respective Governments. They contain members from academia, industry (from service companies to financing/banking agents) and Government. They have the ability to issue guidance and technical reports as well advising the Government on promotion of geothermal. Denmark is an exception in this regard but it already has the support of the Government, and they have clear aims and objectives with regards their energy mix. The UK has a geothermal industry but it is still in its infancy stage and could therefore benefit from closer working relations, not least to share more data and place it in the public domain, but also to form an independent risk / guarantee fund. If, for instance, 1 in 5 geothermal wells is likely to fail, the risk of one failed well could be shouldered by a more unified geothermal umbrella organisation.

Ultimately it is proposed the over-arching issue that particularly affects the UK’s renewable outlook is due to the legacy of decisions taken 30-40 years ago in response to the oil crises of 1973 and 1979, and the coincidental discovery and development of North Sea gas supplies. The reliance on fossil fuels is not something unique to the UK; all countries assessed still rely largely on fossil fuels. However, decisions regarding energy efficiency and energy saving measures have been implemented over a longer time-scale than that seen in the UK. Denmark in particular can be seen as a renewable leader, success having been built on many years of driving towards one aim; independence from fossil fuels. The Netherlands, Germany and France may have based their future around gas and nuclear power, as did the UK, but geothermal has been prioritised in a different manner. We are playing catch-up with an industry that has expanded largely across Continental Europe but has failed to make an impact in the UK due to the framework in which UK energy policy currently operates.

3.13 References

AECOM, 2013, Study into the Potential for Deep Geothermal Energy in Scotland, The Scottish Government.

Agemar, T., Alten, J., Ganz, B., Kuder, J., Kuehne, K., Schumacher, S., and Schulz, R., 2014a, The Geothermal Information System for Germany - GeotIS: ZDGG, v. 165, no. 2, p. 129-144.

Agemar, T., Weber, J., and Schulz, R., 2014b, Deep Geothermal Energy Production in Germany: Energies, v. 7, no. 7, p. 4397.

Antics, M., Bertani, R., and Sanner, B., 2013, Summary of EGC Country Update Reports on Geothermal Energy in Europe, Proceedings European Geothermal Congress, Pisa, Italy, 2013.

Arup, 2011, Review of the generation costs and deployment potential of renewable electricity technologies in the UK: Department of Energy and Climate Change (DECC).

Atkins, 2013, Deep Geothermal Review Study Final Report: Department of Energy and Climate Change (DECC).

Barker, J. A., Downing, R. A., Gray, D. A., Findlay, J., Kellaway, G. A., Parker, R. H., and Rollin, K. E., 2000, Hydrogeothermal studies in the United Kingdom: Quarterly Journal of Engineering Geology and Hydrogeology, v. 33, no. 1, p. 41-58.

Batchelor, T., Curtis, R., Ledingham, P., and Law, R., 2015, Country Update for the United Kingdom: Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Berendsen, H. J. A., 2005, The Rhine-Meuse delta at a glance (Mid-conference excursion guide), 8th International Conference on Fluvial Sedimentology: Delft, Netherlands.

Bertani, R., 2015, Geothermal Power Generation in the World 2010-2014 Update Report, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

BGR, 2015, Geoviewer, Volume 2016, Bundesanstalt für Geowissenschaften und Rohstoffe / Federal Institute for Geosciences and Natural Resources (BGR).

Boissier, F., Lopez, S., Desplan, A., and Lesueuer, H., 2009, 30 Years of Exploitation of the Geothermal Resource in Paris Basin for District Heating: Geothermal Resources Council Transactions, v. 33, p. 355-360.

Bonté, D., van Wees, J.-D., and Verweij, J. M., 2012, Subsurface temperature of the onshore Netherlands: New temperature dataset and modelling: Netherlands Journal of Geosciences - Geologie en Mijnbouw, v. 91, no. 4, p. 491-515.

Bozau, E., and van Berk, W., 2013, Hydrogeochemical Modeling of Deep Formation Water Applied to Geothermal Energy Production: Procedia Earth and Planetary Science, v. 7, p. 97-100.

Busby, J., 2010, Geothermal Prospects in the United Kingdom, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.

Castillo, C., and Ignatiadis, I., 2012, Sulfate-reduction state of the geothermal Dogger Aquifer, Paris Basin (France) after 35 years of exploitation: Analysis and consequences of bacterial proliferation in casings and reservoir, Proceedings, Thirty-Sixth Workshop on Geothermal Reservoir Engineering: Stanford University, Stanford, California.

Castillo, C., Kervevan, C., Jacquemet, N., Hamm, V., Bouchot, V., and Sanjuan, B., 2011, Assessing the Geochemical Impact of Injection of Cooled Triassic Brines into the Dogger Aquifer (Paris Basin, France): A 2D Reactive Transport Modelling Study, Proceedings, Thirty-Sixth Workshop on Geothermal Reservoir Engineering: Stanford University, Stanford, California.

Cofely GDF-Suez, 2012, The Southampton (UK) District Energy Scheme: An Integrated Energy Scheme using Geothermal Energy.

-, 2015, Geothermal, http://www.cofely-gdfsuez.co.uk/solutions/district-energy/district-energy-technologies/geothermal/.

Comité National Français de Géologie, 1980, Geology of the European countries: Denmark, Finland, Iceland, Norway, Sweden, London : Graham & Trotman.

Crampon, N., Custodio, E., and Downing, R. A., 1996, The hydrogeology of Western Europe: a basic framework: Quarterly Journal of Engineering Geology and Hydrogeology, v. 29, no. 2, p. 163-180.

Danish Energy Agency, 2012a, Accelerating green energy towards 2020: The Danish Energy Agreement of March 2012.

-, 2012b, Energy Policy in Denmark.

DECC, 2012, The Future of Heating: A strategic framework for low carbon heat in the UK.

-, 2015, Energy Consumption in the UK (2015): Overall energy consumption in the UK since 1970.

-, 2016, National Heat Map, http://tools.decc.gov.uk/nationalheatmap/.

Deutsche Bank Research, 2014, The changing energy mix in Germany: Deutsche Bank Research.

Downing, R. A., and Gray, D. A., 1986a, Geothermal Energy: The potential in the United Kingdom London, HMSO.

-, 1986b, Geothermal resources of the United Kingdom: Journal of the Geological Society, v. 143, no. 3, p. 499-507.

Duin, E. J. T., Doornenbal, J. C., Rijkers, R. H. B., Verbeek, J. W., and Wong, T. E., 2006, Subsurface structure of the Netherlands - results of recent onshore and offshore mapping: Netherlands Journal of Geosciences - Geologie en Mijnbouw, v. 85, no. 4, p. 245-276.

EGEC, 2016, EGEC Members Volume 2016, http://egec.info/membership/egec-members/.

EIA, 2015, Energy Units and Calculators Explained, Volume 2016, http://www.eia.gov/energyexplained/?page=about_energy_units.

Foulger, G. R., Wilson, M. P., Gluyas, J. G., Julian, B. R., and Davies, R. J., in prep., Global review of induced and triggered earthquakes: Earth Science Reviews.

Fuchs, S., and Förster, A., 2014, Well-log based prediction of thermal conductivity of sedimentary successions: a case study from the North German Basin: Geophysical Journal International, v. 196, no. 1, p. 291-311.

Geological Survey of the Netherlands (TNO), 2016, DINOloket Nomenclature (Deep), https://www.dinoloket.nl/nomenclature-deep.

Geothermal District Heating (GEODH), 2016, UK - An Integrated Energy Scheme using Geothermal Energy in Southampton, Volume 2016, Geothermal District Heating (GEODH), http://geodh.eu/wp-content/uploads/2015/01/UK-Southampton-GeoDH.pdf.

Global Energy Network Institute, 2014, Geothermal Energy in France, http://www.geni.org/globalenergy/library/renewable-energy-resources/world/europe/geo-europe/geo-francebig.shtml.

Goldstein, B., Hiriart, G., Bertani, R., Bromley, C., Gutiérrez-Negrín, L., Huenges, E., Muraoka, H., Ragnarsson, A., Tester, J., and Zui, V., 2011, Geothermal Energy, Cambridge, United Kingdom and New York, NY, USA, Cambridge University Press, IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation.

Huenges, E., 2010, Geothermal Energy Systems: Exploration, Development and Utilization, WILEY-VCH Verlag GmbH & Co. KGaA.

Huenges, E., Holl, H. G., Legarth, B., Zimmermann, G., and Saadat, A., 2004, The Stimulation of a Sedimentary Geothermal Resrvoir in the North German Basin: Case Study Groß Schönebeck, Proceedings, Twenty-Ninth Workshop on Geothermal Reservoir Engineering: Stanford University, Stanford, California.

IGA, 2016, International Geothermal Association - Affiliated Members, http://www.geothermal-energy.org/about_the_iga/affiliated_organizations.html.

International Energy Agency, 2010, Geothermal Essentials.

-, 2011a, Energy Policies of IEA Countries - Denmark.

-, 2011b, Technology Roadmap: Geothermal Heat and Power.

Kabus, F., and Jäntsch, E., 1995, The geothermal heating plant at Waren-Papenburg: Experience and modernisation., Proceedings of the World Geothermal Congress, Firenze, Italy, 18-31 May 1995.

Kramers, L., van Wees, J.-D., Pluymaekers, M. P. D., Kronimus, A., and Boxem, T., 2012, Direct heat resource assessment and subsurface information systems for geothermal aquifers; the

Dutch perspective: Netherlands Journal of Geosciences - Geologie en Mijnbouw, v. 91, no. 4, p. 637-649.
Lokhorst, A., and Wong, T. E., 2007, Geology of the Netherlands, *in* Wong, T. E., Batjes, D. A. J., and Jager, J. d., eds., Royal Netherlands Academy of Arts and Sciences, Volume 341, p. 341-346.
Lopez, S., Hamm, V., Le Brun, M., Schaper, L., Boissier, F., Cotiche, C., and Giuglaris, E., 2010, 40 years of Dogger aquifer management in Ile-de-France, Paris Basin, France: Geothermics, v. 39, no. 4, p. 339-356.
Lubitz, C., Motagh, M., and Kaufmann, H., 2014, Ground Surface Response to Geothermal Drilling and the Following Counteractions in Staufen im Breisgau (Germany) Investigated by TerraSAR-X Time Series Analysis and Geophysical Modeling: Remote Sensing, v. 6, no. 11, p. 10571.
Lund, J. W., and Boyd, T. L., 2015, Direct Utilization of Geothermal Energy 2015 Worldwide Review, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.
Manning, D. A. C., Younger, P. L., Smith, F. W., Jones, J. M., Dufton, D. J., and Diskin, S., 2007, A deep geothermal exploration well at Eastgate, Weardale, UK: a novel exploration concept for low-enthalpy resources: Journal of the Geological Society, v. 164, no. 2, p. 371-382.
Mathiesen, A., Kristensen, L., Nielsen, C., Weibel, R., Hjuler, M., Røgen, B., Mahler, A., and Nielsen, L., 2013, Assessment of sedimentary geothermal aquifer parameters in Denmark with focus on transmissivity, European Geothermal Congress, Pisa, Italy.
Mathiesen, A., Nielsen, L. H., and Bidstrup, T., 2010, Identifying potential geothermal reservoirs in Germany: Geological Survey of Denmark and Greenland Bulletin, v. 20, p. 19-22.
Mortimore, R. N., Wood, C. J., and Gallois, R. W., 2001, The Upper Cretaceous rocks of the British Isles, British Upper Cretaceous Stratigraphy, Geological Conservation Review Series, No.23, Joint Nature Conservation Committee: Peterborough, p. 558.
Norden, B., Förster, A., and Balling, N., 2008, Heat flow and lithospheric thermal regime in the Northeast German Basin: Tectonophysics, v. 460, no. 1–4, p. 215-229.
Ofgem, 2016, Tariffs that apply for Non-Domestic RHI for Great Britain, https://www.ofgem.gov.uk/environmental-programmes/non-domestic-renewable-heat-incentive-rhi/tariffs-apply-non-domestic-rhi-great-britain.
Planete Energies, 2015, The History of Energy in France, http://www.planete-energies.com/en/medias/saga-energies/history-energy-france.
Regenspurg, S., Wiersberg, T., Brandt, W., Huenges, E., Saadat, A., Schmidt, K., and Zimmermann, G., 2010, Geochemical properties of saline geothermal fluids from the in-situ geothermal laboratory Groß Schönebeck (Germany): Chemie der Erde - Geochemistry, v. 70, Supplement 3, p. 3-12.
REN 21, 2015, Renewables 2015 Global Status Report: Renewable Energy Policy Network for the 21st Century.
Røgen, B., Ditlefsen, C., Vangkilde-Pedersen, T., Nielsen, L. H., and Mahler, A., 2015, Geothermal Energy Use, 2015 Country Update for Denmark, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.
Rollin, K. E., Kirby, G. A., Rowley, W. J., and Buckley, D. K., 1995, Atlas of Geothermal Resources in Europe: UK Revision: British Geological Survey, Regional Geophysics Series, Technical Report WK/95/07.
Schellschmidt, R., Sanner, B., Pester, S., and Schulz, R., 2010, Geothermal Energy Use In Germany, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.
Seibt, A., Hoth, P., and Naumann, D., 2000, Gas solubility in formation waters of the North German Basin - Implications for geothermal energy recovery, Proceedings of the World Geothermal Congress, Kyushu - Tohoku, Japan, May 28-June 10 2000.
Seibt, P., Kabus, F., and Hoth, P., 2005, The Neustadt-Glewe Goethermal Power Plant – Practical Experience in the Reinjection of Cooled Thermal Waters into Sandstone Aquifers., Proceedings World Geothermal Congress, Antalya, Turkey, 24-29 April 2005.

Seibt, P., and Kellner, T., 2003, Practical experience in the reinjection of cooled thermal waters back into sandstone reservoirs: Geothermics, v. 32, no. 4–6, p. 733-741.

Tesmer, M., Möller, P., Wieland, S., Jahnke, C., Voigt, H., and Pekdeger, A., 2007, Deep reaching fluid flow in the North East German Basin: origin and processes of groundwater salinisation: Hydrogeology Journal, v. 15, no. 7, p. 1291-1306.

Thomson, C., and Harrison, G., 2015, Life cycle costs and carbon emissions of wind power: ClimateXChange / University of Edinburgh.

Underhill, J. R., 2003, The tectonic and stratigraphic framework of the United Kingdom's oil and gas fields: Geological Society, London, Memoirs, v. 20, no. 1, p. 17-59.

Ungemach, P., 2001, Insight into geothermal reservoir management district heating in the Paris Basin, France: GHC Bulletin, v. 22, p. 3-13.

Ungemach, P., and Antics, M., 2015, Assessment of Deep Seated Geothermal Reservoirs in Selected European Sedimentary Environments, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

United Nations, 1997, Kyoto Protocol to the United Nations Framework Convention on Climate Change.

-, 1999, Trends in Consumption and Production: Household Energy Consumption.

van Heekeren, V., and Bakema, G., 2015, The Netherlands Country Update on Geothermal Energy, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Van Wees, J.-D., Kramers, L., Kronimus, A., Pluymaekers, M. P. D., Mijnlieff, H., Juez-Larré, J., Bonté, D., van Gessel, S., Obdam, A., and Verweij, H., 2010, Geothermal Energy in the Netherlands: The ThermoGIS project, www.lbeg.niedersachsen.de/download/52200.

Verhoeven, R., Willems, E., Harcouët-Menou, V., De Boever, E., Hiddes, L., Veld, P. O. t., and Demollin, E., 2014, Minewater 2.0 Project in Heerlen the Netherlands: Transformation of a Geothermal Mine Water Pilot Project into a Full Scale Hybrid Sustainable Energy Infrastructure for Heating and Cooling: Energy Procedia, v. 46, p. 58-67.

Vernier, R., Laplaige, P., Desplan, A., and Boissavy, C., 2015, France Country Update, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Weber, J., Ganz, B., Schellschmidt, R., Sanner, B., and Schulz, R., 2015, Geothermal Energy Use in Germany, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

West, I., 2002, Geological Map of Western Europe, http://www.discoveringfossils.co.uk/europe_geology.htm.

Williams, T., 2014, Southampton District Energy Scheme Performance (Pers. Comm.).

Younger, P. L., Gluyas, J. G., and Stephens, W. E., 2012, Development of deep geothermal energy resources in the UK: Proceedings of the Institution of Civil Engineers - Energy, v. 165, no. 1, p. 19-32.

Younger, P. L., and Manning, D. A. C., 2010, Hyper-permeable granite: lessons from test-pumping in the Eastgate Geothermal Borehole, Weardale, UK: Quarterly Journal of Engineering Geology and Hydrogeology, v. 43, no. 1, p. 5-10.

Ziegler, P. A., 1980, Northwest European Basin: Geology and Hydrocarbon Provinces, *in* Miall, A. D., ed., Facts and principles of World petroleum occurrence, Volume Memoir 6, Canadian Society of Petroleum Geologists.

Chapter 4:

The Late Field Life of the East Midlands Petroleum Province – A New Geothermal Prospect

This Chapter has been published within the Quarterly Journal of Engineering Geology and Hydrogeology (Hirst et al., 2015)

4.1 Abstract

Modification of existing oilfield infrastructure could deliver a cost effective way to extend the economic life of depleted onshore oilfields. Naturally warm connate and injection water contained within these fields could be initially co-produced with remaining oil reserves and used to deliver clean, cheap, non-intermittent heating. The East Midlands Petroleum Province contains over 30 fields with a production history spanning 95 years (Craig et al., 2013), and we have chosen to examine the Welton Field in detail. Well data for the Welton Field has been analysed to ascertain extractable heat within both oil and non-oil (water) bearing strata within the field. Production rates were calculated to be 728 $m^3\ d^{-1}$ oil and 854 $m^3\ d^{-1}$ water. These values also include productivity of intervening largely water bearing intervals. Target formation temperature at 1500 m was determined to be 52.5°C, allowing an extractable heat energy calculation to be undertaken for a range of temperature differentials. For a 30°C depletion in temperature, 1.6 MW_t extractable heat is available within the Welton Field alone. This equates to 14,040 MWh of heat energy available for consumption by the domestic market or within commercial greenhouses.

4.2 Introduction

Deep geothermal energy extraction is a technology that is little developed within the UK, yet has scope to be a major component of the renewable energy industry. In the UK, this type of energy resource is currently only used on a small scale in Southampton, where one single well exploits water at 76°C from the Triassic Sherwood Sandstone aquifer (1729-1767 m TVD) within the Wessex basin. The Sherwood Sandstone in particular displays both lateral and vertical permeability that has allowed water to be pumped at a rate of 864 – 1037 m^3 d^{-1} (Williams, 2014). The heat contained within extracted water is used to both heat and chill retrofitted public buildings within the centre of Southampton, and also provides heat for approximately 400 domestic flats (Southampton City Council, 2009). A total of 14,000 MWh of heat is produced per annum from the Southampton well, which equates to 18% of the total district heating mix (the remainder being provided by fuel oil and natural gas).

A recent Deep Geothermal Review Study of the UK (Atkins, 2013) focused on assessing geothermal power generation alone, with any excess heat considered as a potential usable by-product. However, low enthalpy geothermal resource exploitation (heat for heat) is seen by many as a more viable proposition. Geothermal systems extracting heat from deep onshore saline aquifers have already been proven to be a viable resource both in the UK and across Europe. The Paris District Heating Scheme currently operates 34 well doublets, extracting warm water (54-80°C) from the Mid Jurassic Dogger Formation. The Dogger Formation limestone aquifer has produced a yearly total of 1,240 GWh when producing from all 34 doublets (Lopez et al., 2010). Germany has also seen a geothermal renaissance having developed over 200 direct use deep geothermal systems. Operating geothermal systems have an installed geothermal capacity of 250 MW_t (Agemar et al., 2014) producing 925 GWh yr^{-1} consumable energy for district heating, space heating and thermal spa use. This value does not include the additional contribution made by shallow / near surface geothermal systems. Geothermal power production has risen to an installed capacity of 27.1 MW_e, equating to 36 GWh yr^{-1} consumable energy.

4.2.1 The cost of geothermal energy

The primary cost driver in constructing a geothermal scheme is that associated with the drilling of a geothermal borehole. It is estimated that 60-70% of the total cost of a geothermal scheme is spent on the drilling phase (Arup, 2011). The Science Central borehole, drilled in Newcastle-Upon-Tyne between 2011-12 to 1.8 km depth, cost approximately £1.2m to drill (Younger et al., 2012); logging, testing and completion of the borehole would more than double this cost. The Science Central exploration borehole was drilled to test the possibility of a geothermal resource being associated with a large fault zone located in the area of concern (the Stublick-90 Fathom Fault Zone). Should the resource be available, a combined heat and power generation scheme could be implemented (Younger et al., 2012).

Control over drilling costs substantially reduces the inherent risk associated with geothermal schemes. One way to control such costs is to use existing infrastructure (both surface and subsurface) to de-risk a potential geothermal exploration target. Such a scheme exists in Tøndor, Denmark (Sanchez and Ofori, 2013). Wells drilled by DONG Energy during the 1980's were sunk to explore the hydrocarbon potential of an anticlinal structure. Target strata were the Early Triassic Sherwood Sandstone Group (formerly Bunter Sandstone), present at 1786-1885 m below ground level. Five wells were drilled but only one indicated a reasonable gas show and as such the area was abandoned as a hydrocarbon prospect. These wells and all associated well data were then utilised more recently to assess the geothermal prospect of the area. Temperatures of 75°C and flow rates of approximately 4804 m^3 d^{-1} are achievable, and may produce an equivalent electrical output of 16 MW_e (Sanchez and Ofori, 2013). The Tøndor project is unique as it effectively "recycled" existing oil well infrastructure for use as a geothermal exploration target, saving both time and money.

Within the UK, in a manner similar to the Tøndor scheme, there is scope to utilise existing oil well infrastructure associated with onshore oilfields for geothermal purposes. One such onshore oilfield is the East Midlands Petroleum Province, which exploits from Carboniferous strata that underlie the area. Whilst the flow rates from Carboniferous strata are not comparable with those quoted from Permo-Triassic sediments, the key point is the wells and infrastructure are already present. The risk and cost of drilling wells has already been taken on, with the by-product (warm water) now being a source of free heat energy that can be exploited by a geothermal scheme.

4.2.2 Previous Geothermal Exploration

An assessment of geothermal resource availability within the UK was undertaken between 1976 and 1986 in response to the oil crisis experienced during the 1970's. A major part of the assessment focused on quantifying the resource contained within Mesozoic Basins. A total of seven boreholes were drilled across the UK during this phase of geothermal exploration: four of these boreholes specifically targeted low enthalpy Mesozoic basins, whilst the remaining three investigated the high enthalpy resource associated with the Carnmenellis Granite, Rosemanowes, Cornwall. The study did not assess or quantify Carboniferous sediments with regards their geothermal potential during the original 1976-1986 study due to lateral variability, post deposition cementation and complex structural features exhibited within these deposits (Holliday, 1986). These parameters affect aquifer properties and makes prediction of permeability, porosity and flow volume difficult to estimate for large areas. Sandstone units, particularly those of Westphalian (Early – Mid Pennsylvanian) age, can be difficult to trace laterally across large areas; units that do display large areal extent can display widespread heterogeneity in permeability and porosity. Namurian Millstone Grit (late Mississippian – early Pennsylvanian) sandstone units display variations in both porosity and permeability, with the latter varying between 7% and 20%. Permeability can vary between 1 mD and 30 mD (DECC, 2010; Holliday, 1986). Recorded production rates from water bores abstracting directly from the Millstone Grit have been shown to vary between 43.2 m^3 d^{-1} (0.5 L s^{-1}) and 4320 m^3 d^{-1} (50 L s^{-1} - Holliday, 1986).

Carboniferous sediments of the East Midlands were initially deposited in an equatorial marine environment, with an increasing shift towards a fluvio-deltaic environment forming throughout the Carboniferous (Collinson, 2005; Glennie, 2005; Holliday, 1986). Therefore, proximal and distal sediments produce large variations in grain size and sorting. This variation in grain size and sorting introduces the heterogeneity that is problematic when characterising Carboniferous geothermal systems, and has led to an incomplete quantification of the total geothermal resource available within these systems. However, with the aid of data from oil wells that exploit Carboniferous strata within the East Midlands Petroleum Province, such units can be much better characterised. This additional data from the East Midlands Petroleum Province opens a new novel way of researching into resource quantification in the East Midlands.

4.3 Study Area

The East Midlands Petroleum Province is an extension of the Southern North Sea Basin and comprises a series of NE-SW trending concealed Carboniferous basins (DECC, 2010). These basins have long been known to contain both oil and gas fields; oil was first extracted for commercial use at Hardstoft, Derbyshire in 1919 (Craig et al., 2013). Additionally, the UK's largest onshore gas field was discovered at Saltfleetby, East Midlands (Hodge, 2003). Over 30 oilfields have since been discovered in the East Midlands, all located west of the Derbyshire Dome (Figure 4-1). Peak oil production across the East Midlands occurred initially during the 1970's in response to increased oil prices imposed by O.P.E.C. The 1990's saw somewhat of a renewal in interest across the area, with peak oil figures occurring during this time. More recently, increasing water cut within all fields has seen many wells being shut in.

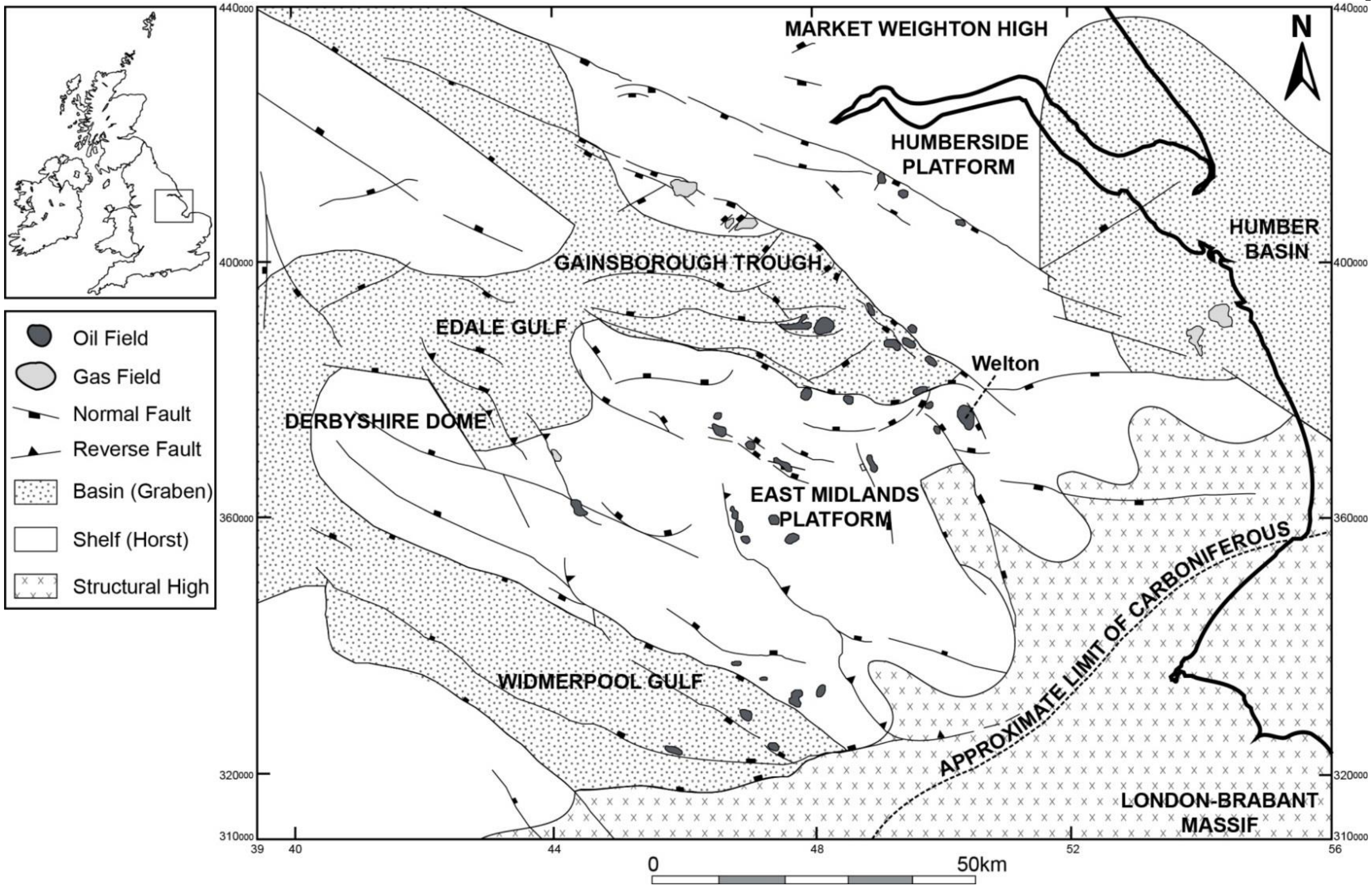


Figure 4-1: The East Midlands Petroleum Province. The Carboniferous block and basin structure across the East Midlands has been identified on the map, along with associated oil and gas fields (DECC, 2010).

4.3.1 The Welton Field: Location & Stratigraphy

The second largest onshore oil reserve in the UK (to Wytch Farm on England's south coast) was discovered at Welton in 1981 (DECC, 2010). Located 8 km northeast of Lincoln City, the Welton field has 45 penetrations associated with it (80 individually named wells in total i.e. a sidetrack of a previously drilled well), the base of which range between 1169 m (Welton B28) and 2536 m (Welton A1) true vertical depth (TVD). Of these individual wells, 45 have temperature data and 22 have porosity and permeability data. Between 1981 and 2008, 2,699,245 m^3 oil was produced from the field. The field has three sites where wells are clustered; the 'A' site, 'B' site and 'C' site, as detailed on Figure 4-2. Wells in the 'A' site primarily exploit strata in the northern half of the field, whilst wells in the 'B' and 'C' site target central and southern areas.

Figure 4-2 shows the general location of the Welton field, along with the distribution of wells across the area. The field is located on the East Midlands Platform; a fault bounded block south of the Gainsborough Trough (see Figure 4-1). The Gainsborough Trough formed one of the main depocentres of sedimentation during the Carboniferous, and hosts several oilfields including Gainsborough, Beckingham and Glentworth.

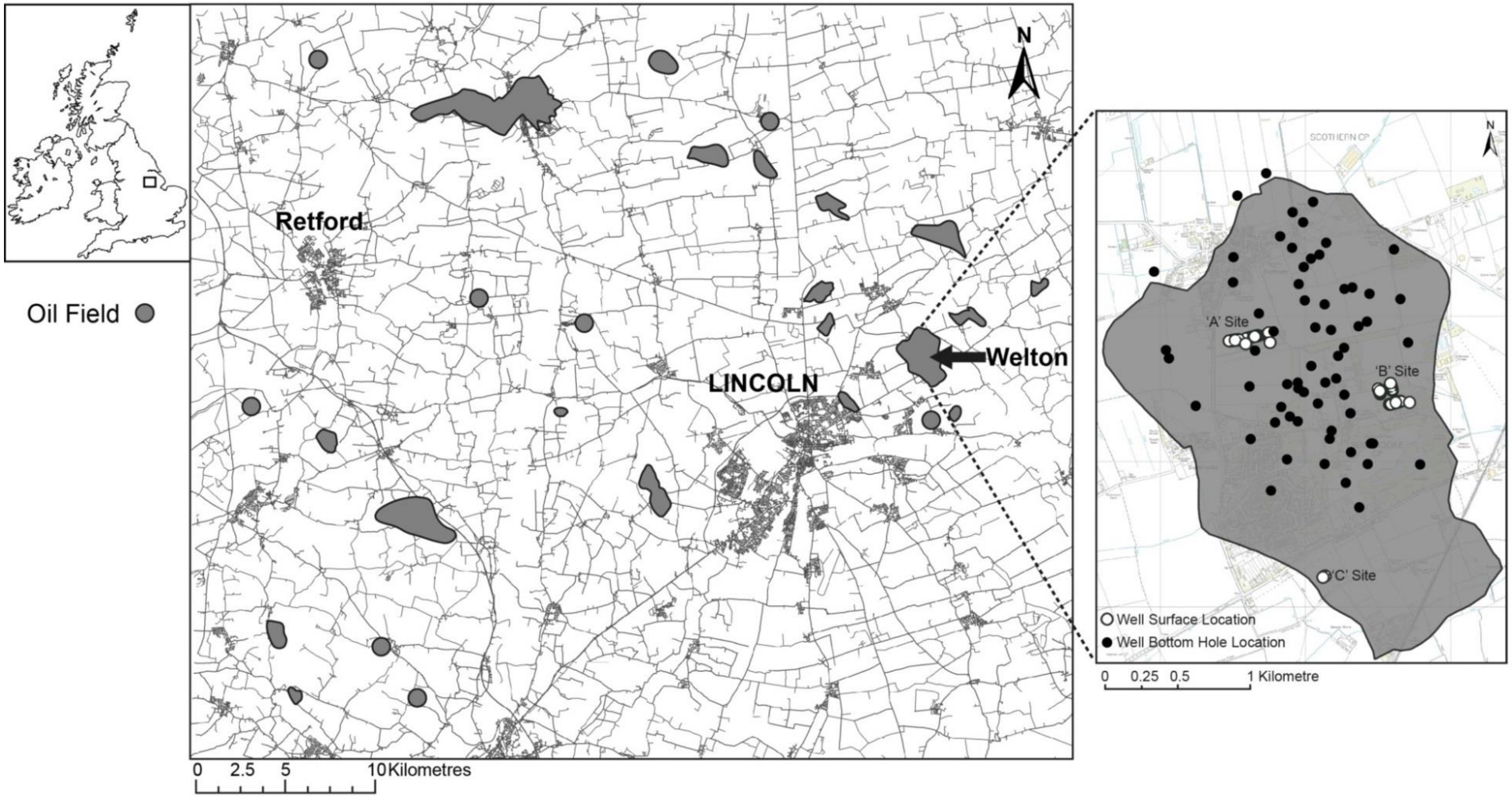


Figure 4-2: General location of the Welton field and associated oil wells (DECC, 2013b).

4.3.2 Target Strata

Within the Welton field there are three major oil producing strata. These are the following:

(a) Pennine Middle Coal Measures - Westphalian ‘B’ : Brinsley-Abdy Rock;

(b) Pennine Lower Coal Measures - Westphalian ‘A’ : Upper Succession (Deep Soft Rock, Deep Hard Rock, Parkgate, Tupton);

(c) Pennine Lower Coal Measures - Westphalian ‘A’ : Basal Succession (Unit 1a, 1b, 1c, 2a, 2b, 2c, 3a, 3b).

These strata are generally comprised of fine to coarse sandstone interbedded with siltstone and mudstone intervals. In addition to these strata, one well (A4) has produced from the Dinantian Limestone (Craven Group). The Dinantian Limestone is not considered as an important oil producer, but will be considered as a geothermal reservoir for reasons outlined further on within this section. The Brinsley-Abdy unit will not be considered as a geothermal reservoir due to its relatively shallow depth and thus correspondingly lower reservoir temperature. All horizons are marked on the stratigraphic column and generalized cross section in Figure 4-3. Approximately 67% of wells drilled in the Welton field target the Basal Succession, whilst 23% target the Upper Succession and 8.5% the Brinsley Abdy. Most wells are completed in only one of the oil bearing intervals as there is lateral variation in the structure and form of these units across the field. The lower successions are generally inter-bedded with siltstone, sandstone and lower porosity / permeable mudstone units, and in some cases there is variable cementation that reduces the net pay of the unit (DECC, 2010).

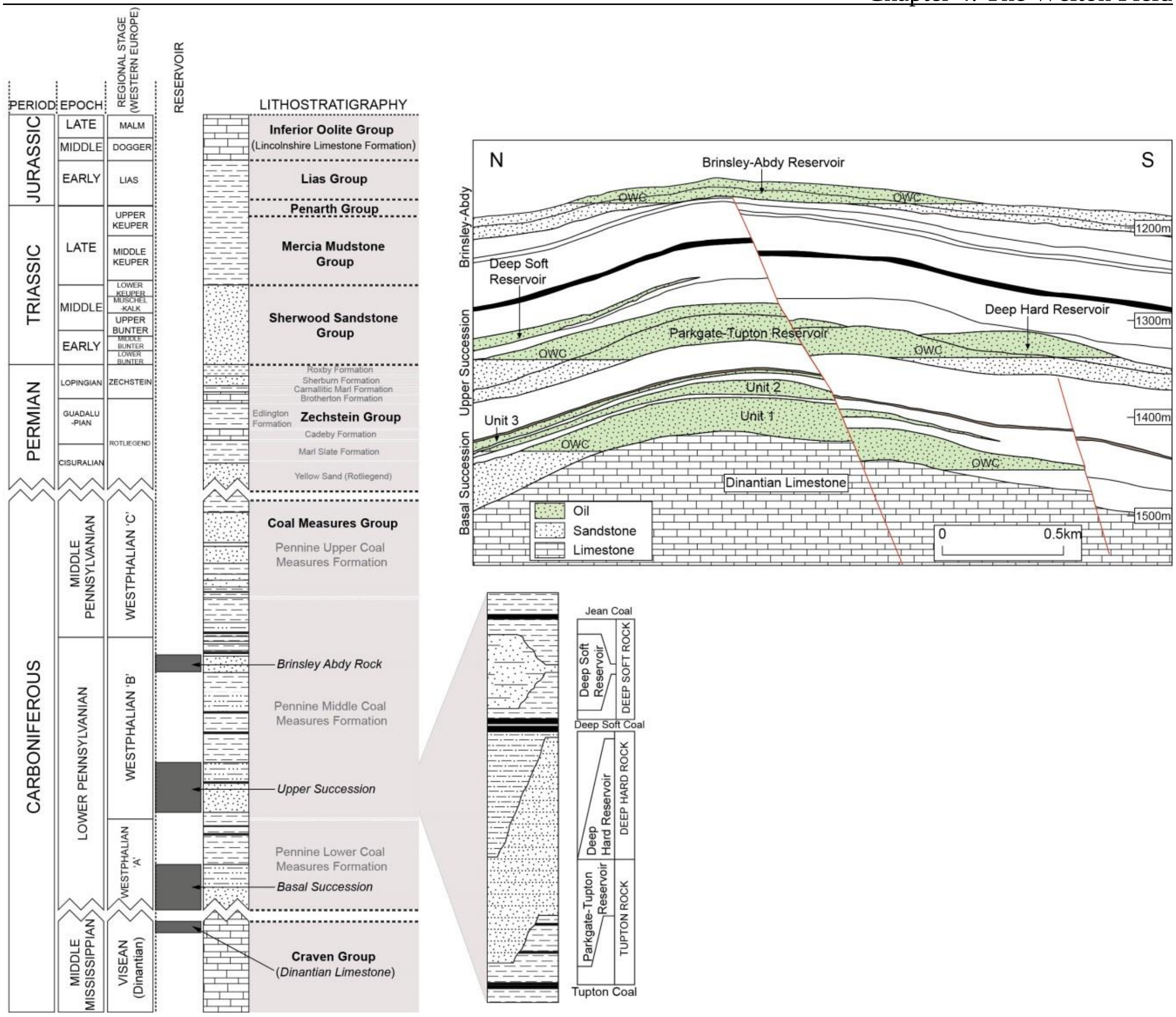


Figure 4-3: Summarised stratigraphy and structure across the Welton field (Roc Oil Company Ltd, 1999).

4.3.2.1 Upper Succession

The Upper Succession is comprised of several sand bodies, namely the Deep Soft Rock, Deep Hard Rock and Parkgate/Tupton units. These are displayed on the expanded section within Figure 4-3. The Parkgate/Tupton unit and Deep Hard Rock are present across the entire Welton field, whilst the Deep Soft Rock is more difficult to trace and displays lateral heterogeneity.

Deep Soft Rock

Well records have described the Deep Soft Rock as fine grained quartzose sandstone, moderately to well sorted with varying degrees of siliceous or calcareous cementation. The unit has been interpreted as fluvio-deltaic facies sediments. Within the northwest of the Welton field (exploited by the ‘A’ site) a major NE-SW trending channel has been interpreted, identified by wells displaying successive fining up sequences. Non-productive wells in the area encountered interlaminated mudstones and sandstones, or mudstone only which have been interpreted as channel bank deposits. In the area surrounding the 'B' site, coarsening up sequences have been identified and interpreted as crevasse splay deposits that are related to another possible channel sequence to the east of Welton. The 'C' site has been interpreted as being more proximal to this channel, which explains the reduction in net pay of the Deep Soft Rock at the 'C' site.

Deep Hard Rock

The Deep Hard Rock is generally comprised of a fine grained sandstone with varying levels of sorting (from poor to moderate) and weak siliceous/kaolinitic cement. The unit is occasionally interbedded with mudstone and sandstone, and rarely contains poorly sorted, angular conglomeritic sections. The facies has been interpreted as multiple channel events containing basal conglomerates, erosive channels and pinch out sand bodies. The net reservoir is well developed within a belt across the northeast of the Welton field, and a belt across the southern part of the field.

Parkgate-Tupton Rock

The Parkgate-Tupton Rock was initially classed as one sand body. In some areas there is a clear distinction between the Parkgate unit and Tupton unit. The unit as a whole is similar to the Deep Hard Rock. The unit varies from fine to coarse quartzose sandstones, poorly to moderately well sorted containing an argillaceous and/or siliceous cement with frequent conglomeritic horizons and fining up sequences. Some wells encountered thick beds of argillaceous mudstone interpreted as channel bank collapse causing the entrainment of large mudstone blocks.

4.3.2.2 Basal Succession

Basal succession sedimentation has been interpreted to be on a lower delta plain, analogous to the Mississippi lower delta plain. In the Welton field it has been broken down into three broad reservoir units; Unit 1, Unit 2 and Unit 3. As shown on Figure 4-1, Welton lies on the structural high known as the East Midlands Shelf. Prior to the deposition of the Basal Succession sedimentation rates across the Welton field were relatively slow because of the aforementioned structural relief. The sub-basins surrounding the Welton field were steadily being infilled by a major deltaic deposystem bringing clastic material into these areas. The onset of sedimentation that formed the Basal Succession occurred when these basins were full. This deltaic deposystem resulted in multi-storey multi-channel systems developing across what was previously dominated by a prograding deltaic deposystem. The deltaic system continued to prograde onto the East Midlands shelf bringing coarse sand onto the irregular Dinantian karst limestone surface.

The Basal Succession is made up of three separate channel systems, with Unit 1 (the lowermost unit) being the thickest and most extensive. Unit 1 is, on average, a 33 m thick sand that has been interpreted to be a high-energy distributary channel system sealed by an overlying mudstone. Laterally within Unit 1, smaller crevasse splay deposits and interdistributary bay systems can be identified within core. Unit 2 has been identified as another smaller channel event and averages 11 m thickness. Unit 2 is split further into zones 2a, 2b and 2c; the 2b zone has been identified as the sand-prone reservoir zone. Unit 2 thins and is entirely replaced by a mudstone/siltstone equivalent in the southern part of the field, interpreted as the distal equivalent. Averaging 9 m, Unit 3 is the thinnest of the Basal Succession units and is similarly split into 3a and 3b. Zone 3a is a thick mudstone unit, whilst 3b is a single channel sand deposit that thins to a silt towards the south of the field.

4.3.2.3 Dinantian Limestone

The full thickness of the Dinantian Limestone has been proven by only one well: Welton A1. Well A1 encountered 993 m of limestone before entering Carboniferous volcanics at the base of the succession. Pre-Cambrian basement was then penetrated (noted to be chloritic phyllite). In general, however, wells penetrate anywhere between 23 m and 108 m into the limestone. The overlying Basal Succession sits unconformably on the Dinantian Limestone, the surface of which is irregular, undulating and generally weathered. Well records indicate in four wells there is a medium – coarse, moderately sorted, sub-angular sandstone interval (<40 m) of Dinantian age overlying the main carbonate sequence with a maximum recorded air permeability of 972 mD and porosities ranging between 12-17% (Well A2). This is called the ‘clastics’ sequence that does not appear to be laterally persistent.

Weathering of the limestone prior to the deposition of the Basal Succession can be seen across the field, evidence for which is manifested in a lack of vertical homogeneity. Where the ‘clastics’ succession is not seen, the limestone tends to grade from chalky amorphous limestone to micritic limestone through to crystalline limestone with abundant stylolites, many of which contain bituminous resin. Oil bleed has been noted to occur from fractures and stylolites in 11 wells. Argillaceous interbeds also occur in upper sections of the limestone which are laterally discontinuous. Visible porosity can be vuggy but is mostly poor. Flow of both oil and water is through fracture flow rather than intergranular flow. Stylolites appear not to form barriers to flow in this field.

4.3.3 Core Data

Horizontal permeability (KH) versus porosity crossplots for the Deep Soft, Deep Hard and Parkgate-Tupton Rock can be found in Figure 4-4 Additional data taken directly from oilfield core reports have been presented in Figures 4-5a and 4-5b. These plots have been interpreted within the discussion section of this paper.

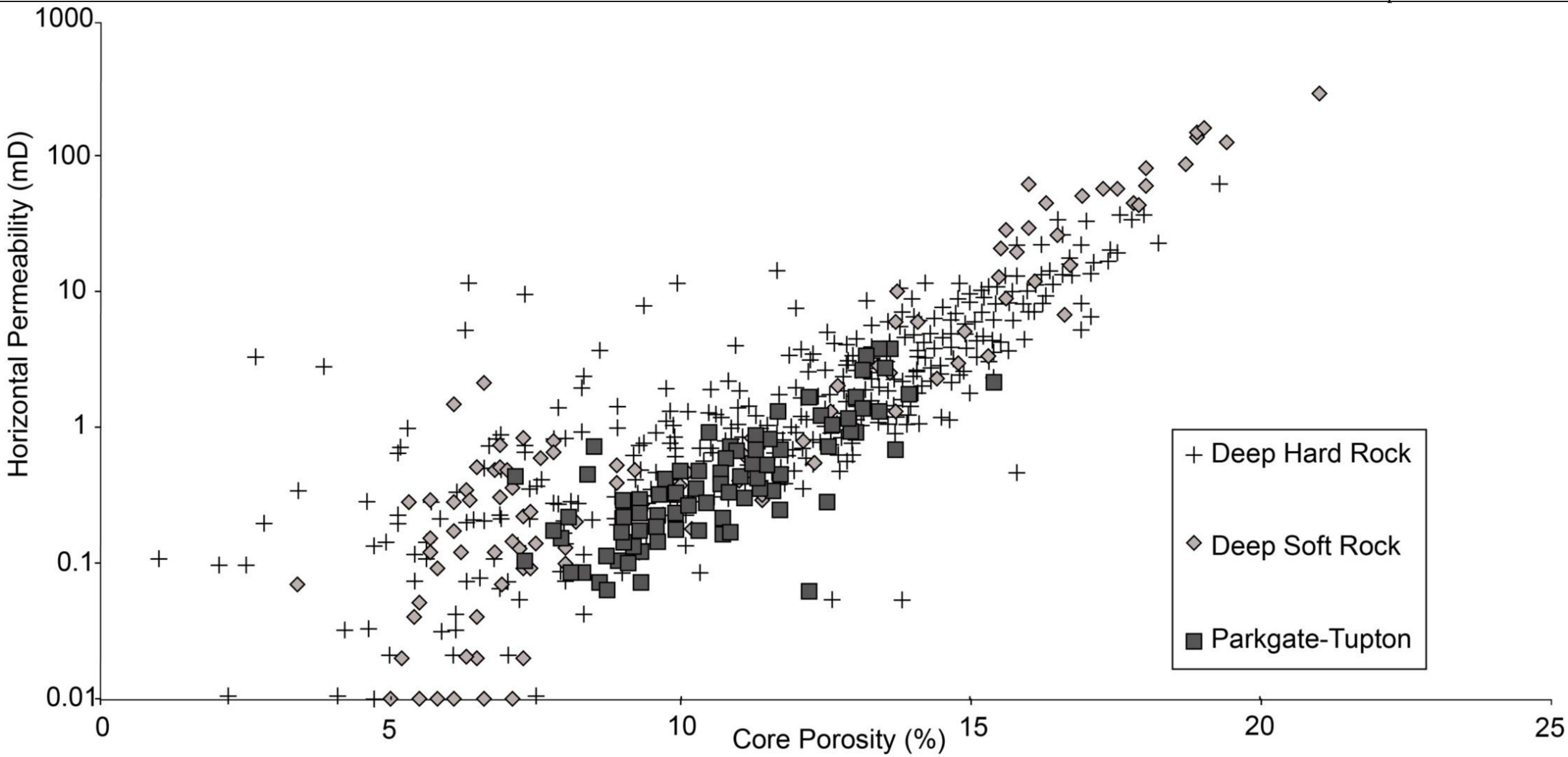


Figure 4-4: Summarised cross plot for data taken from the three main producing strata within the Upper Succession.

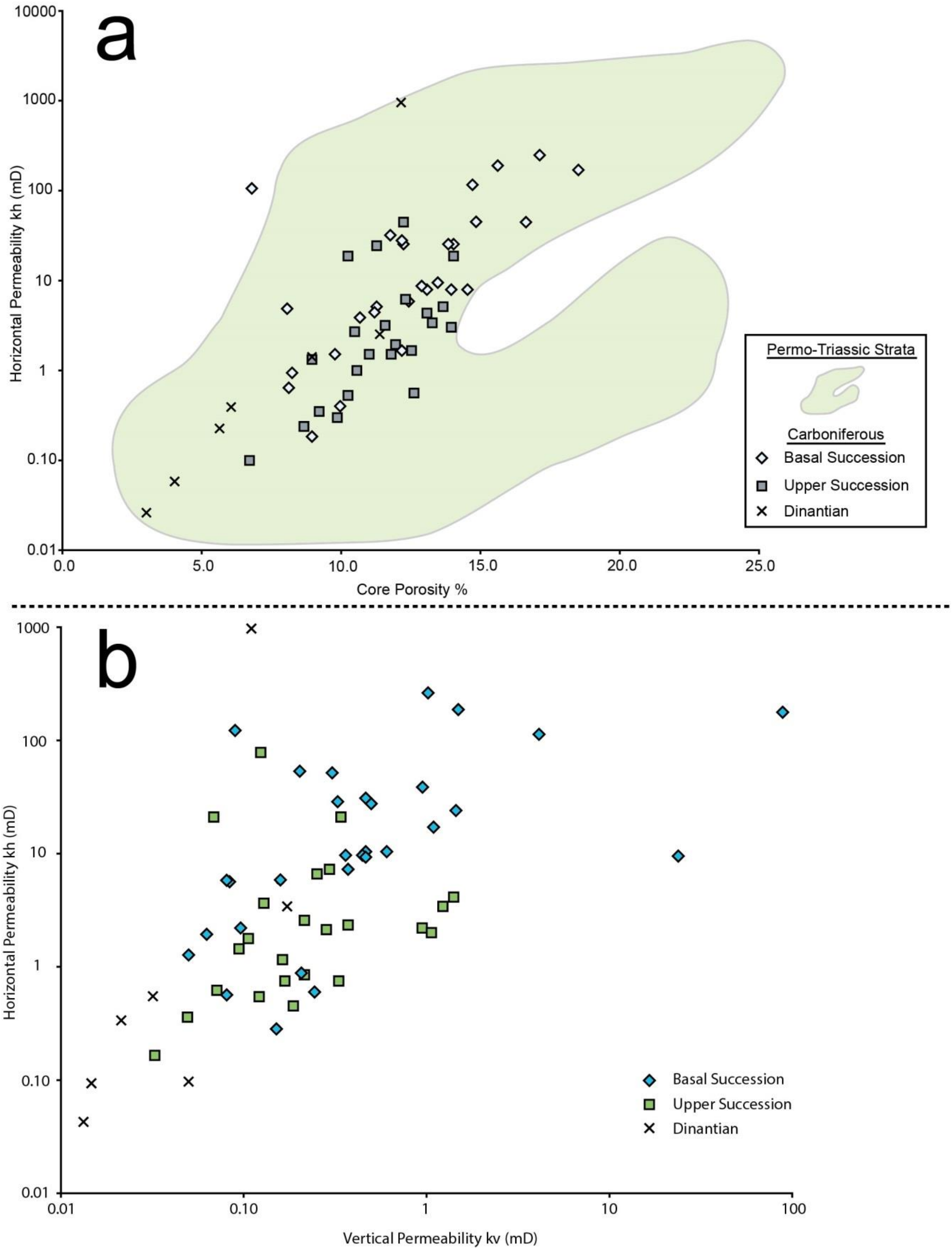


Figure 4-5: 'a' - Crossplot of data taken from oilfield core reports for the Welton field, with the shaded area indicating where Permo-Triassic sandstone and mudstone units plot for comparison (Permo-Triassic data from Colter and Ebbern (1978). 'b' - KV/KH ratio for the three target successions within the Welton field. Data taken from oilfield core reports.

4.4 Methods

Temperature, pressure, density, specific heat capacity and flow rate data are available for the Welton field within well records held by IGas Energy PLC (IGas). These data were used to derive stabilised temperature, extractable heat value and well flow potential.

4.4.1 Horner Temperature Correction

Data accumulation from existing oil wells includes a measure of Bottom Hole Temperatures (BHT). In the majority of cases these values are not true representatives of the formation temperature; they represent the temperature of circulated drilling fluid which is at a lower temperature than the formation temperature (Deming, 1989; Förster, 2001). The recording of equilibration temperatures is uncommon due to the time required for the borehole to stand before equilibration is reached.

Deming (1989) provides a comprehensive comparison of the main methods of BHT correction. Many use an empirical approach to provide a temperature correction, whereas some use mathematical models to describe the temperature change within a borehole. The latter requires more information from the well records and as such can be harder to resolve. The most commonly used mathematical model utilised for temperature correction is the Horner plot. This takes the following form (Deming, 1989):

$$T_{\infty} = BHT + A \log_e[t + t_{circ} / t]$$ **Equation 4-1: Horner Correction**

Where T_{∞} is equilibration temperature, A is an unknown constant, t is the shut in time (i.e. the time elapsed between cessation of mud circulation and BHT measurement) and tcirc is the drilling mud circulation duration. The Horner method has its limitations as it requires at least two BHT measurements at the same depth but at differing values of t. Two values are also required to plot a time-temperature set. The gradient of the produced plot provides a value for the unknown constant A. Difficulty with the Horner method arises as t_{circ} is not always noted on drilling logs thus making a requirement for a standard circulation time to be applied to the equation. In general, the amount of data required to calculate the temperature correction is rarely noted during drilling. In these instances a standard 4 hour circulation time can be applied where necessary (Deming, 1989).

4.4.2 Temperature Gradient

The gradient has been calculated assuming a temperature of 10°C at ground level. This value reflects the average ground temperature within the East Midlands when constructing geothermal gradients across the field.

4.4.3 Flow Prediction

Darcy's simple radial flow equation has been used to estimate the volume of fluid within strata that have not been used as an oil producer. It takes the following form, described in oilfield units after Economides et al. (2012):

$$q = \frac{k\ h\ (pe - pwf)}{141.2\ \mu\ B\ \ln(re/rw)}$$

Equation 4-2: Darcy's simple radial flow in oilfield units.

Where pe represents external boundary pressure (psi), pwf represents internal bottom hole flowing pressure (psi), q represents flow rate (STB d^{-1}), B represents reservoir oil formation volume factor (res bbl/STB, where STB refers to Stock Tank Barrels), μ represents viscosity (cp), k represents permeability (mD), h represents aquifer thickness (ft), re represents the boundary radius (ft) and rw represents the wellbore radius (ft). Skin factor (a dimensional number used to describe any damage immediately surrounding the well bore that may impair permeability and subsequently pressure, caused as a result of invasion of drilling fluids into the formation) has been neglected from calculations. Oilfield units have been used in this instance as the data from well records is predominantly in this form. The resulting flow rate can be simply converted from STB d^{-1} to $m^3\ d^{-1}$ as 1 STB = 0.1589873 m^3. Rounding error in conversion of units for use in the standard radial flow equation can be avoided by using this method.

4.4.4 Extractable Heat Calculation

Extractable heat stored within water and oil has been calculated using the following equation:

$$\mathrm{Q} = \mathrm{M_{dot}} * \mathrm{C_p} * \Delta\mathrm{T}$$

Equation 4-3: Extractable heat equation

Where Mdot represents mass flow rate (kg s^{-1}), Cp represents specific heat capacity (kJ kg^{-1} K) and ΔT represents the change in temperature (°C). To calculate mass flow rate the density of the fluid in question was taken from the well records, as were specific heat capacities for the oil and water present within the field.

4.5 Analysis

4.5.1 Temperature

A total of 191 individual temperatures were recorded in well records. Of these temperatures, 26 wells had temperature data that satisfied the criteria required for the Horner temperature correction method to be applied. The corrected temperatures are displayed in Table 4-1.

Table 4-1: Horner-corrected temperatures.

Well ID	T (°C)	T_∞ (°C)	Average Depth mTVD	Temperature Increase (°C)	Epoch
A1	50.2	54.5	1599	4.3	Dinantian
A1	70.3	81.4	2536	11.1	Pre Cambrian
A2	48.9	52.3	1540	3.4	Dinantian
A3	49.1	49.2	1506	0.1	Dinantian
A4	49.2	49.8	1537	0.6	Dinantian
A5	44	44	1464	0	Dinantian
A7	49.2	53.4	1544	4.2	Dinantian
A9	51.4	52.4	1456	1	Dinantian
A10	54.7	55.7	1493	1	Dinantian
A10Z	60	60	1516	0	Dinantian
A11	51.5	57.6	1478.5	6.1	Dinantian
A18	53.5	54.1	1494	0.6	Dinantian
B1	45.5	47.2	1461	1.7	Dinantian
B2	46.9	50.1	1471	3.2	Dinantian
B2	49.3	50.3	1524	1	Dinantian
B3	46.1	50.3	1529	4.2	Dinantian
B4	49.4	52.8	1560	3.4	Dinantian
B7	50.5	54.2	1479	3.7	Dinantian
B8	50	50	1500	0	Westphalian
B8	54.6	58.8	1563	4.2	Dinantian
B9	52.4	57	1476	4.6	Dinantian
B10	45	45	1486	0	Dinantian
B15	52.2	52.2	1468	0	Dinantian
C1	49	54.6	1507	5.6	Dinantian
C2	48.4	51.2	1312	2.8	Westphalian
C3	50.7	53	1529	2.3	Dinantian

On average, the corrected temperatures are 2.7°C higher than those measured. This additional 2.7°C has been added onto the whole dataset, which has been plotted and displayed in Figure 4-6.

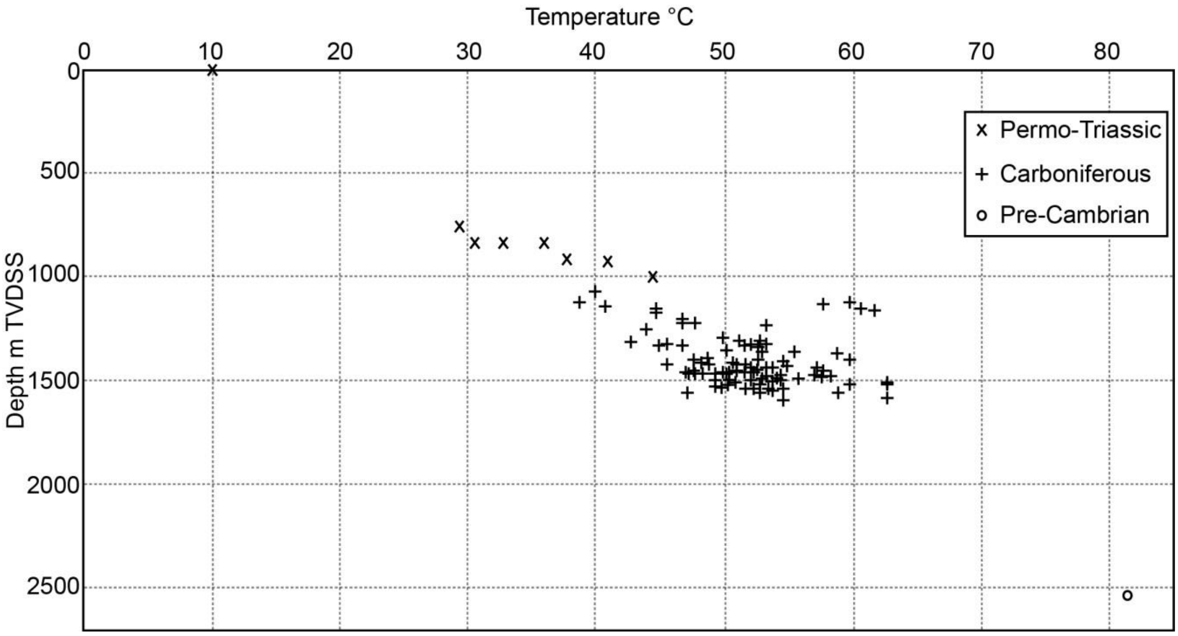


Figure 4-6: All corrected temperature data from the Welton field plotted vs. depth.

Temperature data have also been grouped by well to determine any spatial variation in gradient across the oil field. This required individual wells to have temperature measures in both Permo-Triassic and Carboniferous sediments. Five wells (A1, A4, B1, B8 and C2) satisfied these criteria, the results of which a displayed in Figure 4-7.

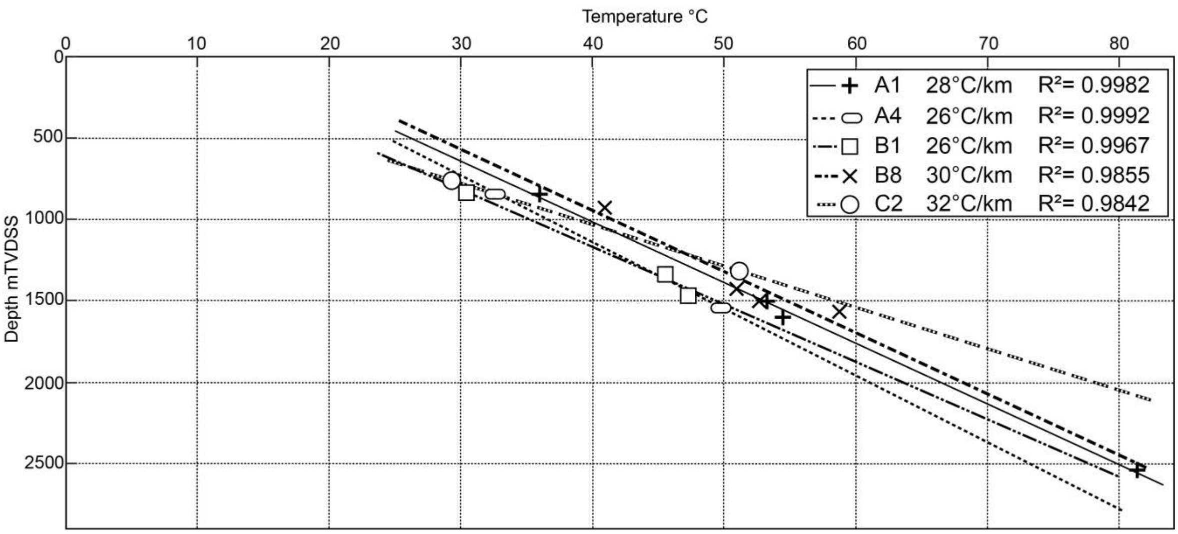


Figure 4-7: Temperature gradients for five individual wells.

4.5.2 Flow Rate

4.5.2.1 Production Rate

Oil and water flow rates from 45 wells recorded between November 1984 and September 2008 are displayed on Figure 4-8. Peak combined oil and water flow rates were recorded in 1997, totalling 343,584 m^3.

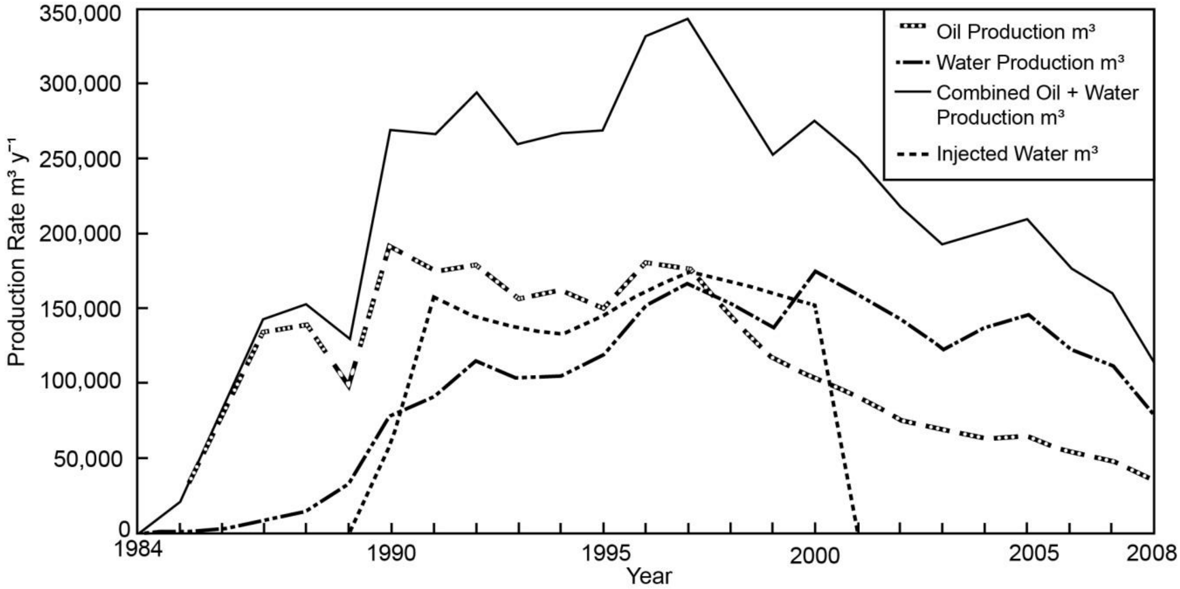


Figure 4-8: Combined oil and water production data summarized for 1984-2008. The data was recorded at well head on a monthly basis, which has been combined to produce yearly totals. Data taken from DECC (2013b).

4.5.2.2 Drill Stem Test (DST) Data

Additional volumes of oil and water were calculated from Drill Stem Test (DST) data obtained for ten wells (A2, A4, A10, A11, B1, B2, B7, B8, B12, C4), with the remaining fluid volumes estimated using a simple radial flow calculation using the parameters based in Table 4-3. In the case of the above 10 wells, DST testing was undertaken on units that displayed potential to be an oil producer. In some cases the unit in question flowed water only, in which case it has not been taken into account in radial flow calculation. In other wells, oil was produced but it was not economic to complete within this particular strata, and in a similar manner has not been taken into account in production rate or radial flow calculations. Table 4-2 shows additional fluid from the wells described above.

Table 4-2: Drill Stem Test data from individual wells across the Welton field.

Well	DST Target Unit	Volume $m^3\ d^{-1}$
A2	Upper Succession (Water)	2.9
A2	Upper Succession (Water + Oil Mix)	2.0
A4	Basal Succession (Water)	23.5
A4	Upper Succession (Oil)	8.6
A10	Upper Succession (Oil)	29.0
A10	Upper Succession (Oil)	7.0
A11	Dinantian (Oil)	3.8
B01	Upper Succession (Oil)	22.1
B01	Upper Succession (Water)	4.1
B02	Upper Succession (Water)	0.5
B02	Upper Succession (Oil)	3.6
B02	Dinantian (Oil)	4.6
B07	Namurian (Oil)	144.5
B07	Namurian (Oil)	20.9
B08	Dinantian (Water)	1.3
B12	Basal Succession (Water)	64.0
C4	Basal Succession (Water)	119.0

4.5.2.3 *Additional Flow Estimation*

Estimating additional flow rate using Darcy's simple radial flow required the definition of several fixed parameters. Formation temperature was taken as 52.5°C, Stock Tank Saline Water density was taken as 1.023 Mg m^{-3} (6.7°API) and average Stock Tank Oil density was taken as 0.848 Mg m^{-3} (35°API). Additional target reservoir parameters have been defined in Table 4-3.

Table 4-3: Radial flow parameters.

<table>
<tr><th colspan="2">`</th><th>Thickness (mTVT)</th><th>Porosity (%)</th><th>Permeability (mD)</th><th>Formation Pressure MPa</th></tr>
<tr><td rowspan="3">Upper Succession</td><td>Deep Soft Rock</td><td>12</td><td>13</td><td>115</td><td rowspan="3">13.8</td></tr>
<tr><td>Deep Hard Rock</td><td>19</td><td>8.4</td><td>1.3</td></tr>
<tr><td>Parkgate-Tupton Rock</td><td>25</td><td>12</td><td>7</td></tr>
<tr><td>Basal Succession</td><td>Basal Succession</td><td>42</td><td>15</td><td>80</td><td>15</td></tr>
<tr><td rowspan="2">Dinantian</td><td>Dinantian</td><td>1000</td><td>8</td><td>0.22</td><td rowspan="2">15.2</td></tr>
<tr><td>Dinantian Clastics</td><td>31.6</td><td>16.2</td><td>-</td></tr>
</table>

Table 4-4 provides a summary of production rate data, DST data and radial flow data.

Table 4-4: Summarised flow rates for all productive strata.

	Oil	Water
Production Rate $m^3 d^{-1}$	484	457
Drill Stem Test Data $m^3 d^{-1}$	244	217
Radial Flow $m^3 d^{-1}$	-	180

Revised flow volumes total 728 $m^3 d^{-1}$ oil and 854 $m^3 d^{-1}$ water. These values can now be used to calculate extractable heat from the Welton field. The uncertainty surrounding these values cannot be reasonably quantified given the overall uncertainty in quantifying a geothermal resource. Temperature and flow rate data are variable (flow rates can vary +/- 100%), so the data are presented based on the provision that until further testing and analysis of the resource are undertaken, these values should be treated with caution.

Table 4-5: Extractable heat summary.

	Oil	Water
Flow Volume $m^3 d^{-1}$	728	854
Flow Volume $m^3 s^{-1}$	8.43E-03	9.89E-03
Density $Mg m^{-3}$	0.848	1.045
Mass Flow Rate $kg s^{-1}$	7.12E+00	1.03E+01
Specific Heat Capacity $kJ kg^{-1} K$	1.8	3.93
Temperature Change (°C)	Heat MW_t	Energy MWh
30	1.6	14040

4.6 Discussion

4.6.1 Reservoir Temperature & Geothermal Gradients

In the absence of heat flow values, the geothermal gradient has been calculated based on the temperature data obtained from well records. To calculate the thermal gradient at least two correct temperature data at different depths are required for each well. Considerations of glaciation and topography effects are also required prior to calculation of thermal gradient. Glaciation and topography can perturb the geothermal gradient down to depths of 1.5 km (Westaway and Younger, 2013) before recovering to follow the regional thermal gradient. The majority of data presented is located within 1.5 km from ground level. Whilst temperature data has been corrected for drilling-induced suppression, the topography and glaciation effect has not been corrected in this instance. The data can be considered a conservative estimate of temperature.

The line of best fit obtained for the whole dataset at Welton yields a temperature gradient of 29°C km^{-1}. Temperature data taken from Carboniferous strata alone does not correlate particularly well. The large spread and poor correlation of temperature data within the Carboniferous more likely reflects spatial variation in geothermal gradients across the Welton field. Given these data have been taken over a small depth interval (<500 m) as well as over a small surface area, it is likely the poor correlation is a factor of this. Fitting a common gradient to the whole dataset, or to an individual geological time period, may not reflect the true gradient across the field. As such, further analysis of individual well gradients has also been used to corroborate the calculated gradient. Spatial variation can be seen when individual well temperatures are plotted (Figure 4-7). An average of these temperature gradients has been calculated to be 29°C km^{-1}, which supports the initial gradient based on the total dataset.

4.6.2 Target Aquifer Properties & Variability

Within the UK, geothermal exploration has previously focused on deep sedimentary aquifers associated with Mesozoic-age basins. The aquifers contained within these basins are laterally continuous sand bodies which in some areas can produce between 864 – 1037 m^3 d^{-1} from a single well point (Williams, 2014). By comparison, the 45 penetrations located across the Welton field produce a similar total volume of fluid (728 m^3 d^{-1} oil and 854 m^3 d^{-1} water), but on average equates to approximately 35 m^3 d^{-1} per individual well. Therefore, direct comparison between these two groups is not possible when assessing flow rate. Crossplots for target geothermal reservoirs within the Welton field are presented in Figure 4-4, 4-5a and 4-5b, which have also been compared with data taken from Permo-Triassic sandstone and mudstones from the Cheshire Basin. The two sets of data show some similarities in trend. However, the data for Carboniferous strata represents targeted core analysis on sections that were being proposed as producers for the oilfield, therefore, introducing a bias in the sampling. It does indicate there are comparable areas of porosity and permeability within the Carboniferous; however these are limited by their lateral extent.

KV/KH ratios were calculated based on core data. Again, these data are for target producing sands and as such introduces bias into the sampling. The data do indicate the sands have a stronger component of horizontal permeability than vertical permeability that may be due to small scale features such as bedding.

The reduced transmissivity seen in Carboniferous target reservoir within the Welton Field is problematic when determining the geothermal potential of a reservoir this age. However, in the case of the Welton Field the impact of reduced transmissivity becomes negligible as the field is already operating. The risk of drilling and hitting unproductive strata will not occur as the risk because the wells are in the ground. The surface infrastructure is already in place to handle and separate fluid mixes before re-injecting waste water back into the field. The heat contained within produced water becomes a waste commodity, one which can be utilised in the vicinity of the field.

4.6.3 Extractable Heat & Heat Demand

The average cost of an ARUP defined median scenario (<10 MW) geothermal system has been estimated to be £5.6m (Arup, 2011). Drilling costs typically account for 60-70% of the total expenditure for a geothermal project, with a further 24% spent on surface infrastructure. Reducing costs associated with drilling could, therefore, be the difference between the success and failure of a geothermal project. There are also gains to be made by reducing surface infrastructure costs. More recent data on the cost of low enthalpy geothermal has been presented by Atkins (2013), but this report only discusses power production. Dumas and Angelino (2015) further discuss costs associated with low enthalpy resources, indicating 50% of the overall budget is typically spent on drilling a low-temperature resource. Drilling is only one part of CAPEX costs and as such further indicates many of the costs associated with geothermal energy development are made before the plant is operational. Dumas and Angelino (2015) describe OPEX costs as being “limited”, as these plants require little input once operating. Financial incentives to the uptake of geothermal technologies are discussed in full within Chapter 3.

Utilising a resource such as Welton benefits from having an existing oil well infrastructure. Wells penetrate transmissive oil and water bearing strata which have produced 2,699,245 m^3 of oil between 1981 and 2008. The Welton Field is served by three drill sites: A site, B site and C site (shown on Figure 4-2). Oil and water that is removed from these areas is piped to the Welton Gathering Centre located at grid reference [TF045748] (Figure 4-9). Here oil, water and gas are separated from six individual fields, the largest of which is the Welton Field. Separated oil is transported away by road tanker, gas is burnt onsite for power generation which then feeds onto the National Grid and water is re-injected (Guion et al., 2008). Given that mixed fluids are already being piped directly to the separating plant, additional costs associated with oil separation need not be considered in this instance as they are already being undertaken. The incorporation of heat pumps into the existing plant will be required and forms the initial expense (should heat be required for heating homes). The heat that is extracted from these fluids becomes an additional commodity, the use of which is limited by the location and type of heat demand.

The commercial value of the heat is currently un-quantified; the demand exists for such a commodity but there is currently no formal way to quantify its value. In this case study, the value of the resource has been put into context based on heat demand and usage within the area surrounding the gathering facility. Typically, low enthalpy geothermal resources are most effective when implemented as a District Heating Scheme, such as that seen in Southampton (Southampton City Council, 2009). A heat demand must be present for such a scheme to be effective due to excessive costs associated with transporting heat over large distances. Williams (2014) estimates the price per kilometre of lagged pipework is approximately £1m, with an associated 0.5-1°C loss in temperature over the same distance (Energie-Cités, 2001). As such, heat demand surrounding the gathering centre at Welton has been assessed for potential heat users.

Ofgem estimates per domestic household, the typical mid-range scenario gas consumption figure is 16,500 kWh per annum, whilst average electricity consumption totals 3,300 kWh (Ofgem, 2011). (DECC, 2013a) state that 66% of domestic energy consumption is used to provide space heating. Therefore, an average household can be assumed to consume 13,000 kWh of energy for space heating per annum. The value of average household consumption can be used to determine the amount of domestic heat that could be offset by the Welton Field using three individual scenarios.

4.6.3.1 Local Demand (<3 km distance from Welton Gathering Centre)

Approximately 2,000 homes are located within a 3 km radius of the Welton Gathering Centre that will on average consume 26,136 MWh heat per annum (Figure 4-9). Assuming a ΔT of 30°C, the Welton field can produce up to 14,040 MWh. Therefore, 53% of homes within a 3 km radius could have their heat consumption cut to zero by the Welton field. If each household had 50% of their heat provided by the Welton field, approximately 2,100 homes could benefit.

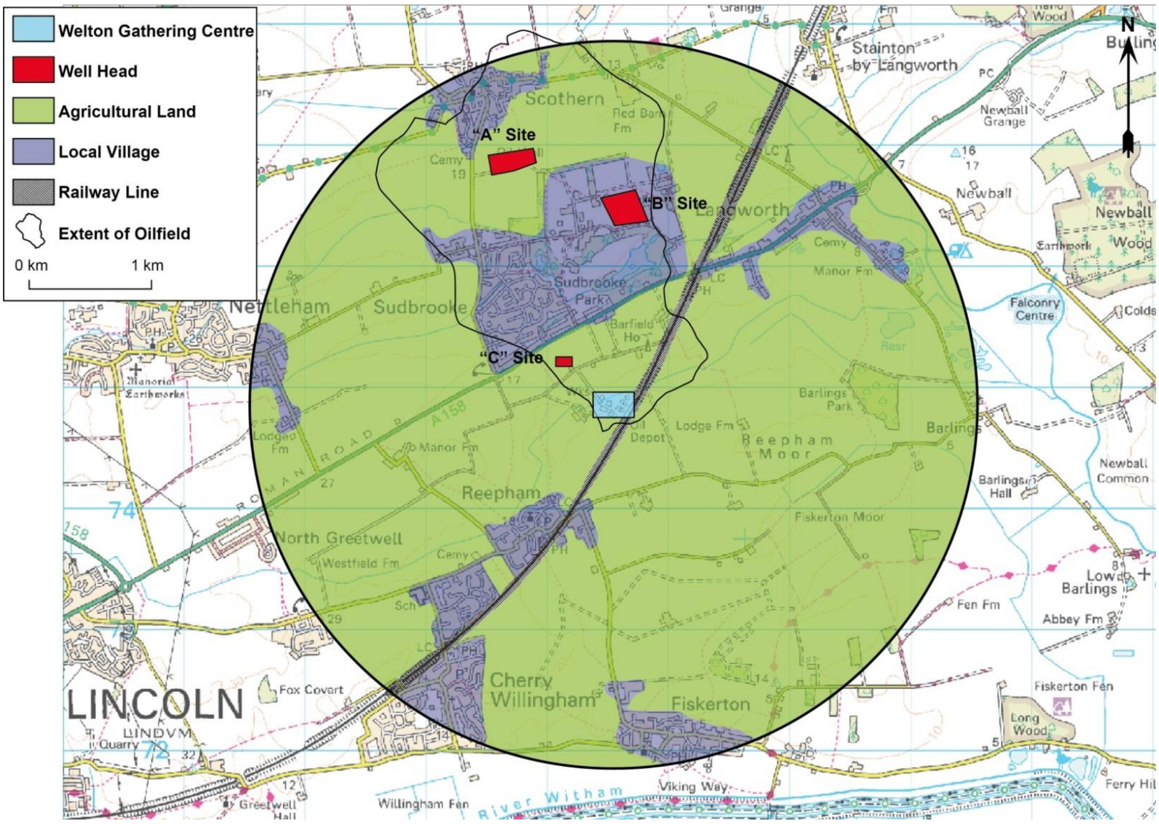


Figure 4-9: Land use within 3 km of Welton Gathering Centre.

To implement such a system would involve constructing a district heat network centred on the Welton Gathering Centre. When constructing such a scheme in an urban area, the costs can be very high. Since the area surrounding the gathering centre is primarily agricultural land, the costs are largely reduced and could make this style of resource use viable.

4.6.3.2 Lincoln City (8 km from well head)

Lying approximately 8 km southwest of the Welton field is the city of Lincoln (Figure 4-10). The domestic energy consumption of Lincoln in 2010 totalled 654.6 GWh.

A third of this energy has been taken as energy used to produce heat and, therefore, it is estimated the domestic heat consumption in the city of Lincoln is 218.2 GWh. Using the heat reserve at Welton could offset this consumption by 5-12% dependant on ΔT.

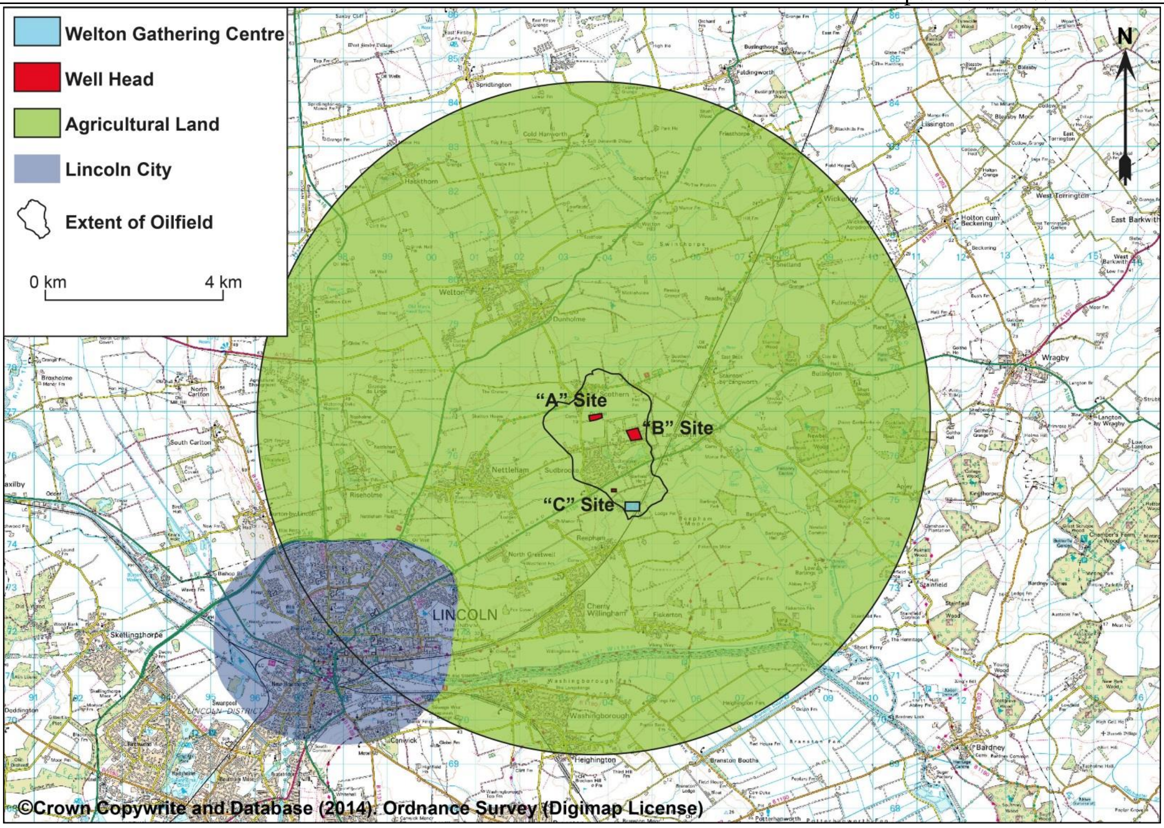


Figure 4-10: The Welton field in relation to Lincoln City.

The lagged pipe network necessary to move hot water from well head to Lincoln city can be efficient enough such that only 0.5°C is lost per kilometre of pipe run, equating to a 4°C loss in temperature. The loss would effectively mean the water temperature as it reaches Lincoln is 48°C, with a re-injection temperature of 18°C. However, the water must first be piped back to the Welton wellhead that would incur a further 4°C drop, therefore re-injecting at 14°C. The energy involved in moving produced water a minimum of 16 km could partly be offset by utilising the gas produced from the field, which on average is 64,597,45 m^3 yr^{-1} (2,281,23749 scfs yr^{-1}). The produced gas is currently used on site for generators and heaters (Ward, 2014) but its use could be turned to power the pumps required to move the water. The efficiency of such a system, however, would suggest it is untenable. The relative saving in drilling costs is not seen as enough for this scheme to work.

4.6.3.3 Agricultural Use: Commercial Greenhouses (1 km from well head)

Food production within the UK has seen a growing reliance on imported foodstuffs to meet consumer demand. Commercial greenhouses provide a means to produce seasonal crops year round whilst also guaranteeing a high yielding crop. Variables such as adverse weather do not impact as heavily on the crop, helping to smooth out peaks and troughs in food production.

The East Midlands forms a large swathe of land that is primarily arable farmland. Within a 1 km radius of the Welton Gathering Centre, 73% of the land is arable farmland, with 19% covered by local villages, 6% occupied by a railway line and the remaining 2% occupied by the Welton Gathering Centre and "C" Site as represented in Figure 4-11.

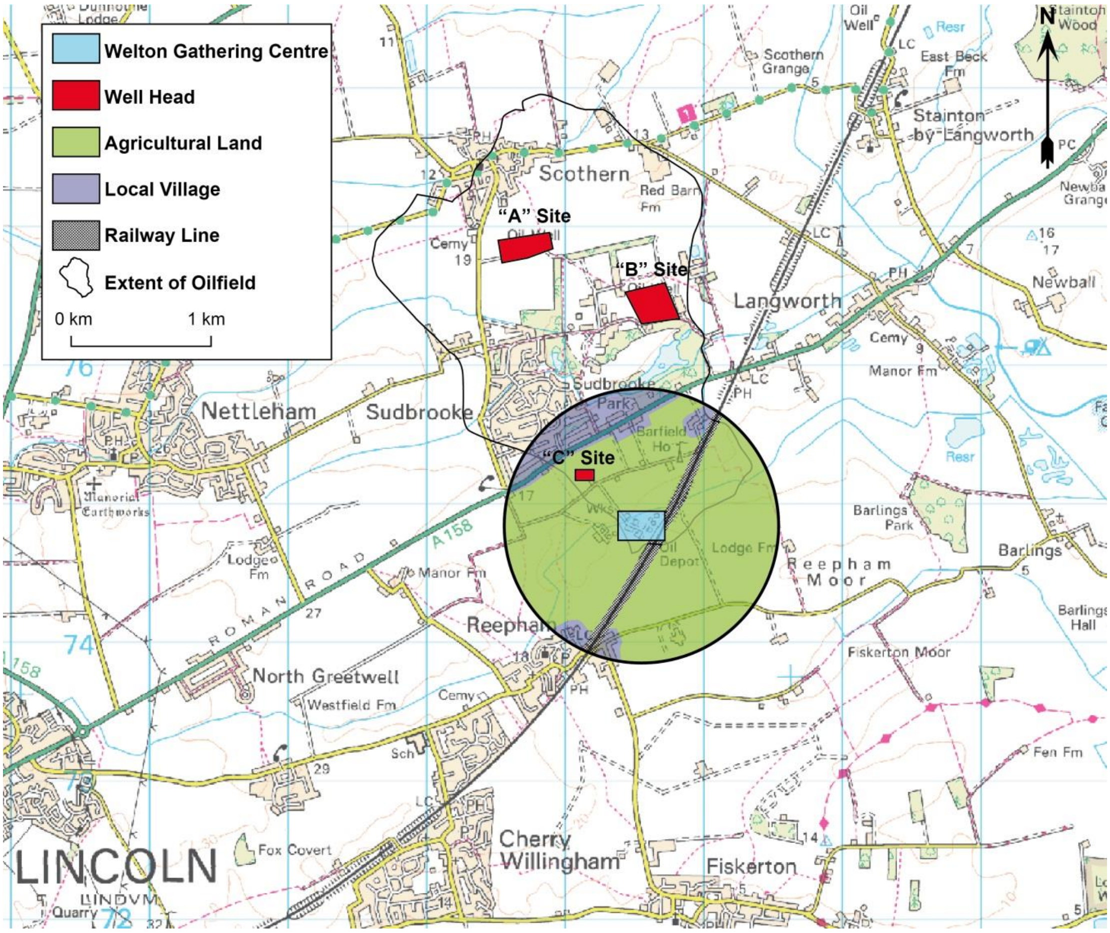


Figure 4-11: Land use within 1 km radius of Welton Gathering Centre.

The extensive agricultural land around gathering centre forms an opportunity for commercial scale greenhouses to be constructed. Temperatures within commercial greenhouses vary depending on the crop type being grown. The Carbon Trust (2004) indicate that energy intensive crops such as tomatoes, cucumbers and peppers require constant temperatures in excess of 18°C. Maintaining 18°C on a large scale is energy intensive and accounts for 90% of the energy used in commercial greenhouses (Sturm et al., 2012). Research undertaken by The Geological Survey of the Netherlands (Kramers et al., 2012) has suggested a minimum resource temperature of 45°C is required for commercial scale greenhouses to work, re-injecting at 25°C. This makes the area surrounding the Welton Field a feasible site for a commercial greenhouse.

Typical heat demand for a commercial greenhouse varies due to crop type and whether the crop requires intensive or extensive management. Sturm et al. (2012) indicate extensive crops require a minimum 155 kWh m^{-2}, whereas intensive crops require up to 450 kWh m^{-2}. Based on 14,040 MWh of extractable heat being available, this equates to between 31,200 m^2 and 90,580 m^2 of land that commercial greenhouses could occupy which would benefit from 100% heat demand being provided by the Welton Field.

4.7 Conclusion

Producing oil fields become less economically viable as oil rate declines and water rate increases. The produced water currently has no value, yet in many fields this water is at a temperature that could be used within a low enthalpy geothermal scheme. Within the UK, geothermal resources have been quantified with regards the low enthalpy geothermal resource held within Mesozoic Basins. Carboniferous strata have not been fully quantified due to their post deposition cementation and complex structural features (Holliday, 1986). Yet despite these complexities one of the UK's largest onshore oil resources lies within Carboniferous strata within the East Midands, proving there is enough transmissivity to permit water abstraction from these units.

The Welton field is part of the East Midlands Petroleum Province, and has produced 2,699,245 m^3 of oil between 1981 and 2008. An assessment of water temperature, flow volume, permeability and porosity has indicated that for a mid-range scenario ($\Delta T = 30°C$), extractable heat totalling 1.6 MW_t is present. This equates to 14,040 MWh of heat energy available for consumption. The produced heat could be used very effectively to offset the heat demand of domestic dwellings located within 3 km of the Welton Gathering Centre. It could also be used to provide heat for commercial greenhouses covering between 31,200 m^2 and 90,580 m^2 of agricultural land. It is unlikely the heat can be transported to Lincoln City for use in a district heat network due to the large distances (8 km+) and associated temperature loss involved.

The Welton field is only one of over 30 fields within the East Midlands. Within a 10 km radius of the Welton wellhead, a total of nine other fields are present, five of which feed into the Welton Gathering Centre directly. In addition, the area of land between these fields is currently unquantified with regards its hydrogeology and geothermal potential. This presents additional resources that are currently un-quantified, and provides an important insight into the geothermal resource held within Carboniferous strata.

Acknowledgements

Thanks go to IGas Energy PLC for supplying the data used within this Chapter. Specific thanks goes to Kelsey Ward of IGas for being a key contact, being on hand to answer additional questions regarding the field and supplying data when requested in a quick and efficient manner. Thanks go to Alison Auld for her help with extractable heat calculations. Thanks also go to Dr. Santo Bains (BP) for supporting knowledge of the oilfield.

4.8 References

Agemar, T., Weber, J., and Schulz, R., 2014, Deep Geothermal Energy Production in Germany: Energies, v. 7, no. 7, p. 4397.

Arup, 2011, Review of the generation costs and deployment potential of renewable electricity technologies in the UK: Department of Energy and Climate Change (DECC).

Atkins, 2013, Deep Geothermal Review Study Final Report: Department of Energy and Climate Change (DECC).

Collinson, J. D., 2005, Dinantian and Namurian depositional systems in the southern North Sea, *in* Collinson, J. D., Evans, D. J., Holliday, D. W., and Jones, N. S., eds., Carboniferous Hydrocarbon Geology: The southern North Sea and surrounding onshore basins, Volume 7, Yorkshire Geological Society, p. 22.

Colter, V. S., and Ebbern, J., 1978, The petrography and reservoir properties of some Triassic sandstones of the Northern Irish Sea Basin: Journal of the Geological Society, v. 135, no. 1, p. 57-62.

Craig, J., Gluyas, J. G., Laing, C., and Schofield, P., 2013, Hardstoft - Britain's First Oil Field: Oil-Industry History, v. 14, no. 1, p. 97-116.

DECC, 2010, The Hydrocarbon Prospectivity of Britain's Onshore Basins, Promote UK 2011, p. 86.

-, 2013a, Energy Consumption in the UK (2013).

-, 2013b, Oil & Gas: Field Data https://www.gov.uk/oil-and-gas-uk-field-data#uk-production-data.

Deming, D., 1989, Application of bottom-hole temperature corrections in geothermal studies: Geothermics, v. 18, no. 5–6, p. 775-786.

Dumas, P., and Angelino, L., 2015, Financing Geothermal Energy, Proceedings of the World Geothermal Congress 2015: Melbourne, Australia.

Economides, M. J., Hill, A. D., Ehlig-Economides, C., and Zhu, D., 2012, Petroleum Production Systems, Second Edition, Pearson Education Inc. Prentice Hall.

Energie-Cités, 2001, Geothermal Energy: District heating scheme, Southampton (United Kingdom).

Förster, A., 2001, Analysis of borehole temperature data in the Northeast German Basin: continuous logs versus bottom-hole temperatures: Petroleum Geoscience, v. 7, no. 3, p. 241-254.

Glennie, K. W., 2005, Regional tectonics in relation to Permo-Carboniferous hydrocarbon potential, Southern North Sea Basin *in* Collinson, J. D., Evans, D. J., Holliday, D. W., and Jones, N. S., eds., Carboniferous Hydrocarbon Geology: The southern North Sea and surrounding onshore areas, Volume 7, Yorkshire Geological Society, p. 12.

Guion, P., Hargreaves, P., and Topham, K., 2008, Oilfields of the East Midlands: Excursion: Mercian Geologist, v. 17, no. 1.

Hirst, C. M., Gluyas, J. G., and Mathias, S. A., 2015, The late field life of the East Midlands Petroleum Province; a new geothermal prospect?: Quarterly Journal of Engineering Geology and Hydrogeology, v. 48, no. 2, p. 104-114.

Hodge, T., 2003, The Saltfleetby Field, Block L 47/16, Licence PEDL 005, Onshore UK: Geological Society, London, Memoirs, v. 20, no. 1, p. 911-919.

Holliday, D. W., 1986, Devonian and Carboniferous Basins, *in* Downing, R. A., and Gray, D. A., eds., Geothermal Energy: The Potential in the United Kingdom: London, HMSO, p. 27.

Kramers, L., van Wees, J.-D., Pluymaekers, M. P. D., Kronimus, A., and Boxem, T., 2012, Direct heat resource assessment and subsurface information systems for geothermal aquifers; the Dutch perspective: Netherlands Journal of Geosciences - Geologie en Mijnbouw, v. 91, no. 4, p. 637-649.

Lopez, S., Hamm, V., Le Brun, M., Schaper, L., Boissier, F., Cotiche, C., and Giuglaris, E., 2010, 40 years of Dogger aquifer management in Ile-de-France, Paris Basin, France: Geothermics, v. 39, no. 4, p. 339-356.

Ofgem, 2011, Typical domestic energy consumption figures.

Roc Oil Company Ltd, 1999, Prospectus, AN 075 965 856.

Sanchez, J., and Ofori, Y., 2013, Petrophysical Evaluation for a Geothermal Project in Tøndor, Sustainable Earth Sciences: Pau, France, European Association of Geoscientists & Engineers (EAGE).

Southampton City Council, 2009, Geothermal and CHP Scheme - Southampton City Council.

Sturm, B., Royapoor, M., Maier, M., Joyce, S., Dong Wang, Y., and Roskilly, A. P., 2012, Dependency of production planning on availability of thermal energy in commercial greenhouses, International Conference on Applied Energy, Suzhou, China.

The Carbon Trust, 2004, Energy Benchmarks and Saving Measures for Protected Greenhouse Horticulture in the UK, Queen's Printers and Controller of HMSO.

Ward, K., 2014, Use of co-produced gas at the Welton Gathering Centre (Pers. Comm.).

Westaway, R., and Younger, P. L., 2013, Accounting for palaeoclimate and topography: A rigorous approach to correction of the British geothermal dataset: Geothermics, v. 48, no. 0, p. 31-51.

Williams, T., 2014, Southampton District Energy Scheme Performance (Pers. Comm.).

Younger, P. L., Gluyas, J. G., and Stephens, W. E., 2012, Development of deep geothermal energy resources in the UK: Proceedings of the Institution of Civil Engineers - Energy, v. 165, no. 1, p. 19-32.

Chapter 5:

The Geothermal Potential Held within Carboniferous Sediments of the East Midlands: A New Estimation Based on Oilfield Data

This Chapter has been published in the Proceedings of the World Geothermal Congress 2015: (Hirst and Gluyas, 2015).

5.1 Abstract

Carboniferous sediments have, to date, been largely ignored when UK geothermal resource assessments have been made. Resources located within deep sedimentary Mesozoic basins, and those associated with radiothermal granites have formed the main focus of resource quantification in recent years. There has been no attempt to formally quantify the resource located within Carboniferous sediments due to their complex structural and diagenetic history.

The East Midlands Petroleum Province is the onshore extension of the Southern North Sea Basin. Oil reserves are typically found in Upper Carboniferous sandstone units, and rarely in Lower Carboniferous (Dinantian) Limestones. Exploration within the East Midlands has led to the discovery of over 30 separate fields. In 2011, IGas Energy PLC (IGas) purchased and now operates 16 of these fields. The well records and production data that were obtained as a result of this procurement has been used to produce a first quantification of the geothermal resource held within Carboniferous strata across the East Midlands. Using known production data, Horner-corrected formation temperatures and oil/water specific gravity from 23 fields, a value of extractable heat has been obtained for each field. In total the geothermal resource has been approximated as being between 1.74 MW_t and 4.36 MW_t. Given these fields cover only 0.78% of the East Midlands total area the potential for a larger geothermal resource base is likely to exist.

Removal and sale of heat from the co-produced water will improve the economics of tail end oil production by lowering the effective total operating expenditure. Reinjection of the cooled water could also help improve sweep and increase the recovery factor of the reservoir; the cooled water having a higher viscosity and hence lower mobility ratio contrast with the oil than would hot water.

5.2 Introduction

With a growing energy gap, developing renewable technologies are becoming increasingly important in the UK energy mix. By 2020, 15% of the UK's final energy consumption must come from renewable energy resources as per Directive 2009/28/EC (2009). The Directive must be undertaken in accordance with the European Council's Directive set in 2007 that states 20% of final energy consumption in the EU must come from renewable resources. As of 2012, 4.1% of the UK's final energy consumption was from renewable sources (DECC, 2013). In addition to the Directive targets, greenhouse gas emissions are required to be "reduced by 12.5% below 1990 emissions by 2008-2012, and by 80% below 1990 emissions by 2050" under the Kyoto Protocol (United Nations, 1997). Geothermal energy is a clean, non-intermittent, low carbon emission technology that fits this remit (Younger et al., 2012).

UK geothermal resources are currently coming back into focus after DECC's Deep Geothermal Challenge fund allowed the sinking of the UK's first geothermal borehole in approximately 20 years (Manning et al., 2007). Further funding for a borehole at Science Central, Newcastle-Upon-Tyne was also made available to explore the low enthalpy resource associated with Carboniferous sandstones at 1.8-2 km depth. These investments built upon the only working deep low enthalpy geothermal scheme in the UK; the Southampton Geothermal Scheme. Here water is extracted at 76°C from the Sherwood Sandstone at a depth of approximately 1.8 km, and although it is currently under refurbishment, it is used to supply a district heating scheme within the city (Adams et al., 2010). More recently, a report by Atkins (2013) commissioned by DECC, has focused attention on resources associated with radiothermal granites at depths of 4-5 km. Whilst it has provided a comprehensive review and quantification of these resources, it did not address the low enthalpy resource associated with deep sedimentary basins; this fell outwith the remit of the project.

Prior to the Atkins report (Atkins, 2013), UK low enthalpy geothermal resources had been initially quantified by Downing and Gray (1986), with a later update published by Rollin et al. (1995). A major assessment of UK geothermal resources was undertaken between 1976 and 1986 which resulted in quantification of the low enthalpy geothermal resource held in Mesozoic basins and radiothermal granites, as well as an estimation of subsurface temperatures. It used existing borehole data made available from various industries / sources to make an assessment of geothermal resources which was subsequently compiled into a catalogue; the Geothermal Catalogue. Whilst the Catalogue has been actively updated, it uses 3057 subsurface temperatures from 1216 sites, 567 of which are from wells >1 km depth from which to interpolate from (Busby, 2010). Based on borehole data collected during the 1987-1995 study, the combined geothermal resource for Mesozoic basins (excluding the Larne basin) was estimated to be 300 EJ (x10^{18} J). UK heat consumption currently totals approximately 3 EJ per annum, suggesting there is enough heat stored in these basins to decarbonise the UK heat requirement for the next 100 years (Younger et al., 2012).

The geothermal resource associated with Carboniferous sediments were discussed but not quantified due to their lateral variability, post deposition cementation and complex structural features (Holliday, 1986; Smith, 1986). Tracing productive strata across large areas is difficult in Carboniferous sediments and attempts to place a value on the geothermal resource contained within these strata has yet to be undertaken. Chapter 2 and 4 demonstrated the complexity in Carboniferous strata, but it also showed that a reasonable geothermal resource is present associated with existing oilfields. What Chapter 5 aims to do, therefore, is to further assess the geothermal resource potential associated with other oilfields in the East Midlands using similar data.

5.3 The Carboniferous geology of the East Midlands

Covering an area of approximately 15,700 km^2, the East Midlands has over 30 hydrocarbon fields contained within it. These fields produce predominantly from Upper Carboniferous strata with some fields occasionally producing from overlying Permian sands. An understanding of the geological history across the East Midlands is required to understand the distribution of productive strata. It also provides an appreciation of the diagenetic history which has a bearing on the porosity and permeability of these rocks. The geology of the East Midlands is displayed in Figure 5-1, along with a more general geological overview of the UK (Crampon et al., 1996). Carboniferous rocks outcrop along the western margin of the East Midlands dipping 1-3° eastwards, where they are progressively buried by a thickening sequence of Mesozoic sediments. The surface location of all but one oil / gas field lies upon Permo-Triassic sediments or younger, also indicated on Figure 5-1.

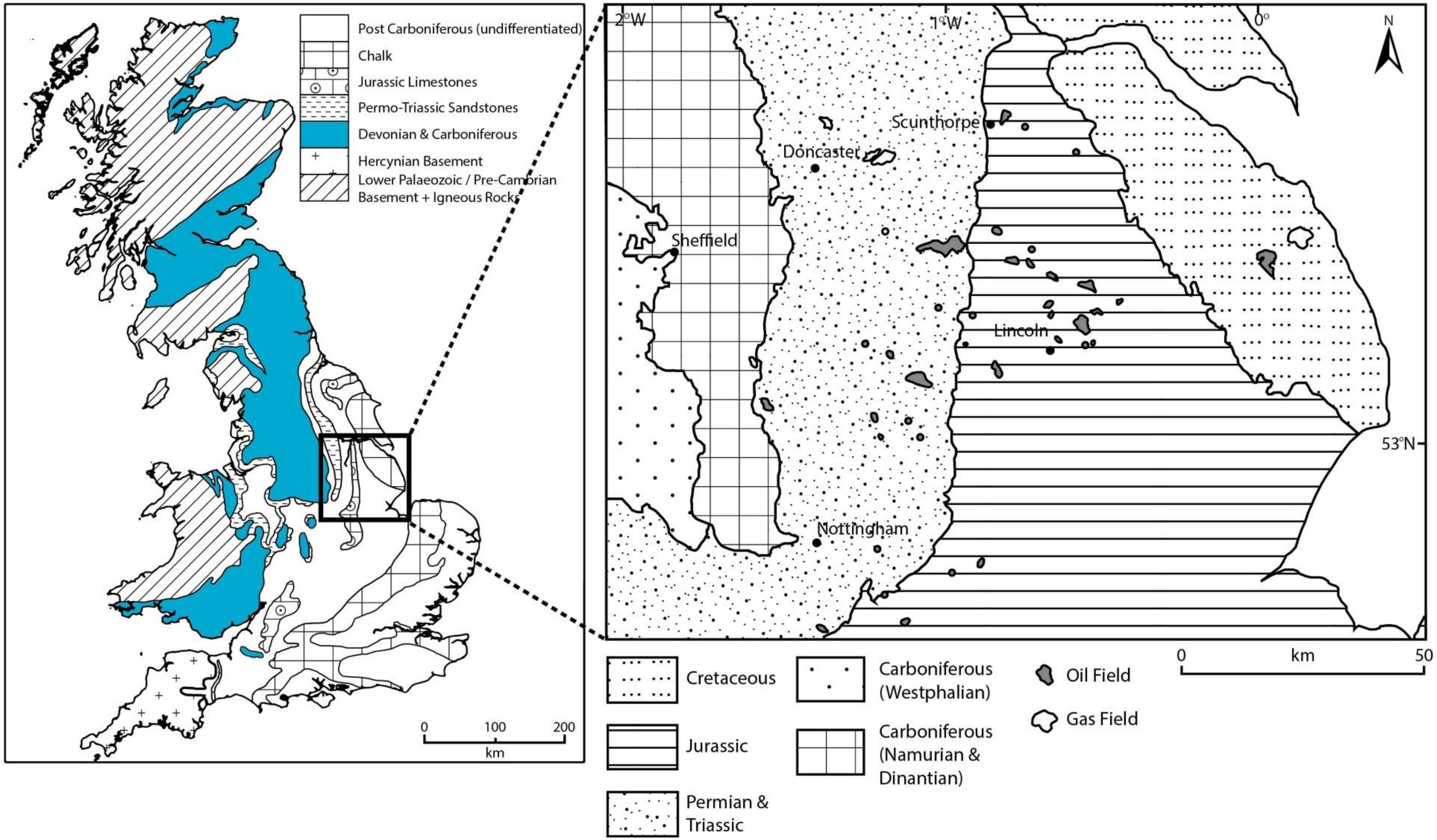


Figure 5-1: Summarised geology of the UK and East Midlands (Crampon et al., 1996; Underhill, 2003)

The East Midlands has undergone several phases of structural deformation, all of which have a bearing on the distribution of productive target strata. Figure 5-2 shows the current structure of the East Midlands, whilst Table 5-1 provides a breakdown of the major structural history of the East Midlands.

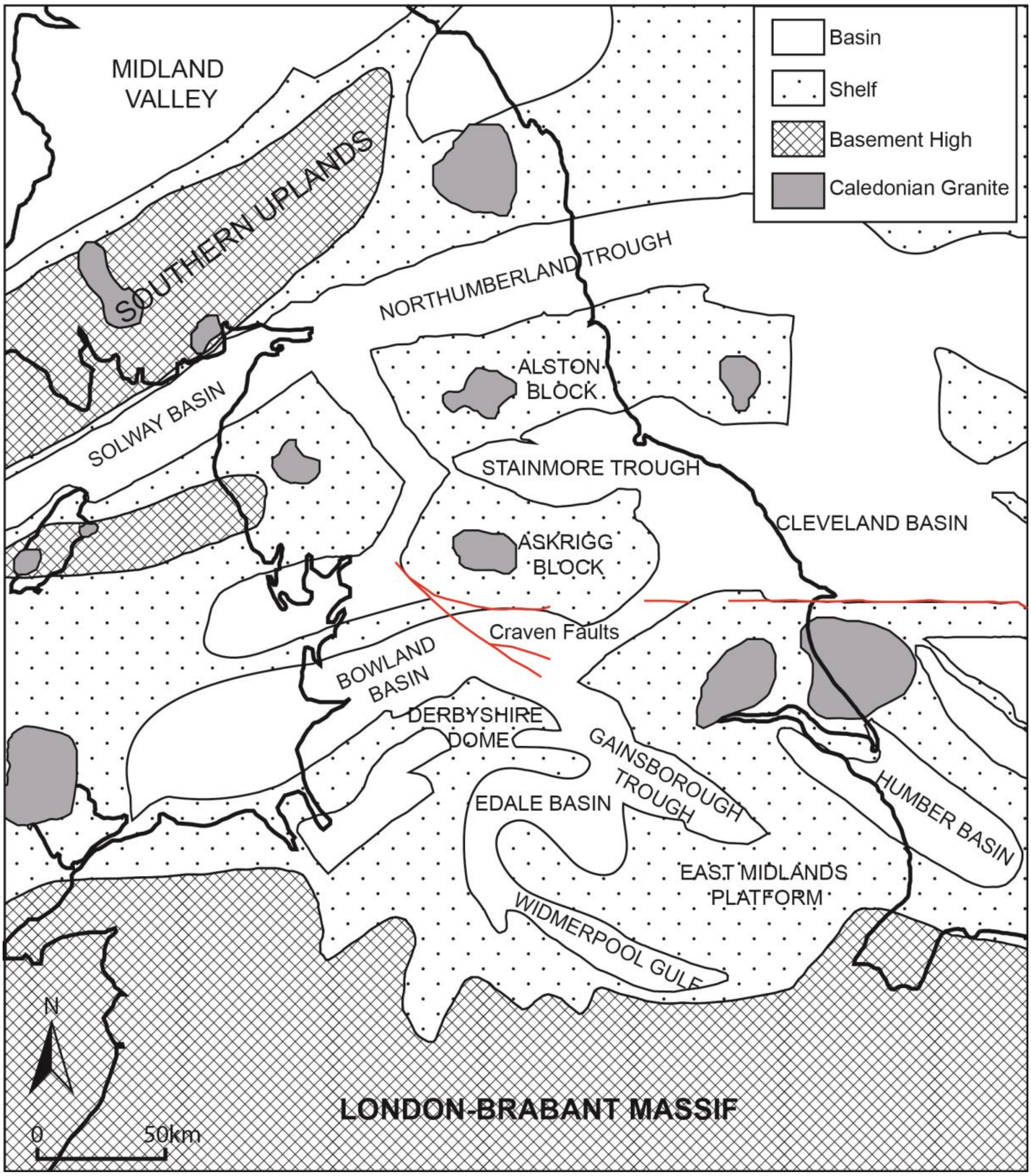


Figure 5-2: Present day structure of England, Wales and Southern Scotland (Waters and Davies, 2006)

Table 5-1: Structural history summary of the East Midlands (DECC, 2010)

Tectonic Event	Timing	Consequence	Stratigraphy
T1 N-S Extension due to subduction south of the London-Brabant Massif. Pulsed rifting.	Late Devonian / Early Carboniferous (Dinantian).	Graben and half graben formation on NW-SE orientation. Controlled by pre-existing structures within Caledonian basement.	Marine environment dominating to the south. Development of carbonate ramps / platforms / shelves on structural highs and calcareous mudstones and turbidites within basins. Incursion of prograding deltas originating from northern England. Notable formation of the Carboniferous Limestone.
T2 Thermal Sag – crustal cooling	Mid to late Carboniferous (Namurian & Westphalian)	Wider scale basin formation; the Pennine Basin. Stretching from the Craven Faults to the London-Brabant Massif. Rift topography buried.	Carbonate deposition ceased due to basin-wide subsidence. Deep marine mudstones dominate across the southern part of the basin. Northern England became dominated by southerly pro-grading deltas, introducing coarse siliciclastics (including the Namurian Millstone Grit). On burial of rift topography, deposits became cyclical; marine mudstones and fluvial channel sandstones dominate caused by high frequency sea level changes.
T3 E-W Compression – Basin Inversion	Late Carboniferous – Early Permian (Late Westphalian – Stephanian).	Uplift and erosion, alteration of major sediment depocentres. Erosion of Dinantian basins whilst pre-existing structural highs remained relatively un-deformed.	Small concentrations of alluvial fan deposits developed (Barren Red Beds: fluvial sandstones, siltstones and mudstones) separated by Permian unconformity.
T4 Tilting / thermal sag	Permian – Mesozoic	Rifting and thermal cooling, formation of Permian basin within the southern North Sea. Tertiary tilting of all rocks, 1-3° to the east.	Deposition includes (but is not limited to) the Sherwood Sandstone, Mercia Mudstone, Magnesian Limestone and chalk.

In summary, potential productive strata can form relatively thick intervals where, for instance, channel sandstones have become stacked to over 100 m thickness. These deposits can persist laterally forming sheet like bodies that display facies variation, such as the Millstone Grit (DECC, 2010). Alternately sandstone bodies can form discrete relatively homogenous lenticular bodies that do not persist across large areas. These have been described as "shoestring" sands (DECC, 2010) and form local aquifers in places. Variable secondary silicification and breakdown of feldspars can be seen affecting these deposits, reducing porosity and permeability. The effects of these processes are difficult to predict across the East Midlands. In some areas the Millstone Grit forms a potable water supply with abstraction rates of up to 4320 $m^3\ d^{-1}$ (50 $L\ s^{-1}$); other areas can support 43.2 $m^3\ d^{-1}$ (0.5 $L\ s^{-1}$) only (Downing and Gray, 1986). It is the inherent variability of Carboniferous strata that has left the East Midlands geothermal resource unquantified.

5.4 The Petroleum History of the East Midlands

The geological and tectonic history has produced controls on the distribution of oil-bearing strata across the East Midlands. Oil has been exploited within the East Midlands since 1919 when oil was discovered within an anticlinal structure comprised of Carboniferous (Dinantian) Limestone (Craig et al., 2013). The discovery was made at Hardstoft; a discovery that led to further exploration and the discovery of more than 30 fields (DECC, 2010). Many of these fields were identified during the 1950's and early-mid 1960's before exploration began to cease. Interest was reignited during the 1970's due to the growing Middle East oil crisis, and many wells were drilled throughout the 1980's. The location of the major oil and gas fields within the East Midlands has been shown on Figure 5-1. The presence of oilfields across the East Midlands shows economic volumes of fluid are extractable from Carboniferous rocks. The petroleum system can be defined by the distribution of source rocks, reservoir rocks and seals. Knowledge of the distribution of these strata, along with knowledge of the geological evolution of the area can help when understanding how porosity and permeability across the field can be retained in some places and lost in others.

5.4.1 Source Rocks

Principle source rocks of the East Midlands are derived from early Namurian shales. These shales are distal pro-delta deposits that developed as a consequence of basin subsidence during T2. Mid to late Dinantian shales that developed during T1 are also classed as source rocks (DECC, 2010). The maturity of these shales has been controlled by the tectonic evolution of the area. Initial burial during T1 and T2, along with enhanced geothermal gradient allowed source rocks to become hydrocarbon-prone. Subsequent basin inversion and exhumation of Upper Carboniferous sediments during T3 effectively caused cessation in source rock maturation, before tilting during T4 allowed oil generation to migrate in an easterly direction (DECC, 2010). Tilting allowed oil to migrate both west and southeast.

5.4.2 Reservoir Rocks

The main reservoir rocks across the East Midlands have been summarized by (DECC, 2010). Namurian sandstones (Millstone Grit) and Westphalian Coal Measure sandstones form the dominant reservoirs across the field. These sandstones have generally formed in channel fills, crevasse splays and fluvial braided river channels. Where these deposits have become stacked, thicknesses of sandstones can reach over 100 m. Oil shows within the Basal Carboniferous, Dinantian Carboniferous Limestone and Basal Permian sands have also been recorded across the field, producing small quantities of oil. DECC (2010) indicate porosity and permeability has been preferentially preserved in these oil bearing reservoirs. Secondary silicification and breakdown of feldspars forming kaolinite and sericite has been avoided due to the presence of oil in these reservoirs.

5.4.3 Seal / Traps

Two types of oil trap within the East Midlands have been identified; structural and stratigraphical (Fraser and Gawthorpe, 1990). DECC (2010) also include sedimentological traps, which describe laterally discontinuous ("shoestring") sands that form discrete oil reservoirs. Basin inversion during T3 created oil-trapping anticlinal fold structures, generating the most typical oil trap in the field (DECC, 2010; Glennie, 2005). Overlap of sandstone onto mudstone or tight limestone has also produced stratigraphic traps that have placed control over the migration of oil in the East Midlands.

5.5 Carboniferous resource assessment

With the provision of temperature and production data for 23 fields within the East Midlands, a basic quantification of extractable heat resource has been made. These fields have extracted economic quantities of oil, water and gas providing evidence that Carboniferous strata have the ability to support large volume fluid extraction. These data can be combined to produce an extractable heat resource estimate based on oilfield production data only, and offers an opportunity to estimate the wider resource contained across the whole East Midlands area.

5.5.1 Temperature

Well logs provided by IGas for 16 fields have had temperature and production data extracted. In addition, data for an additional seven fields has been obtained from DECC and other literature, namely Bailey (2003), Ward et al. (2003), Hodge (2003) and Gluyas and Hichens (2003).

5.5.1.1 Temperature correction

As discussed in Section 2.1.2, temperatures taken directly from well logs must first be corrected to reflect true formation temperature. Bottom Hole Temperatures (BHT) are commonly recorded during the drilling process but are typically lower than expected. During drilling, circulated drill fluids invade the formation causing temperatures to be suppressed below true formation temperature. For equilibration temperatures to be obtained for any given formation the well must be left to stand undisturbed for anywhere between several months to several years (Majorowicz et al., 2004). Consequently equilibration temperatures are rare. Several methods have been derived to correct suppressed temperatures, including the Horner method of correction. It is the Horner method that has been applied to the dataset using the methodology laid out in Hirst et al. (2015).

Twenty One (21) fields had associated temperature data; nineteen (19) of these fields contained data that could be assessed and corrected using the Horner correction method. An average temperature correction factor was calculated to be 3.3°C, which was then applied to the remaining two fields that did not satisfy the criteria for temperature correction.

5.5.1.2 Temperature gradient calculation

Temperatures have been recorded by a range of down-hole logging tools including neutron density, microlog and gamma ray tools, as well as the more customary temperature logging tool.

Temperature gradients were calculated for each field in two ways, based on the level of data available:

- By calculating gradients for individual wells from corrected temperature data collected from all down-hole logging tools.
- By using temperature specific down-hole logs, applying the correction factor where necessary.

All gradients were created using a standard temperature of 10°C at ground level (Met Office, 2014), and where possible used a temperature measure in both Permo-Triassic and Carboniferous strata. Temperature measurements in the depth range 0-300 m (i.e. within Permo-Triassic sediments) have to be treated with caution given the potential suppression of temperatures due to past glaciation and palaeo-topography (Banks, 2008; Westaway and Younger, 2013). Heat flow suppression within the 0-300 m zone can lead to under-estimation of temperatures. Temperatures recover to follow the regional gradient below these depths and as such are not seen as having a major effect on the temperature gradients calculated in each field, considering BHT are within Carboniferous sediments; a linear relationship can be used to determine the gradient.

The latter method of temperature gradient derivation uses data from down-hole temperature logging tools. These data were only available for five fields, but is seen as a more robust way to estimate the gradient across the field as the tool used is temperature specific. Table 5-2 summarises the temperature gradient measures using both methods, including an average measure.

The difference in average between the two methods indicates with relatively good certainty that the margin of error associated with these measurements is reasonable.

Table 5-2: Temperature gradient summary. "ND" denotes No Data. * denotes the average value was used due to lack of data in that particular field.

	Temperature Correction °C	Temperature Gradient °C km^{-1}	Temperature Gradient °C km^{-1}
Beckingham	2.3	32	35
Bothamsall	4.5	34	32.5
Cold Hanworth	5.3	ND	38
Corringham	6.9	ND	32.5
Crosby Warren	7.3	ND	30.5
East Glentworth	0	ND	34
Egmanton	0.51	23	33
Farley's Wood	3.85	ND	39
Fiskerton Airfield	0	ND	24
Gainsborough	2.1	25	28
Kirklington	8.4	ND	50
Long Clawson	1.57	ND	25
Nettleham	0.8	ND	28
Rempstone	3	ND	34
Scampton	3.1	ND	31
Scampton North	5.45	ND	31
South Leverton	*3.3	ND	36
Stainton	2.7	ND	32
Torksey	*3.3	ND	30
Welton	2.66	35	29
West Firsby	2.2	ND	33
AVERAGE	3.3	30	33

5.5.2 Production rates

Twenty three (23) fields have associated production data. These data were assessed for both oil and water production. Peak production rates have been identified in each field and are noted in Table 5-3.

Table 5-3: Geothermal Resource Summary Table

Field ID	Field Area (km^2)	Production Rate $m^3\ d^{-1}$		Geothermal Resource (MW_t)	Output at 80% Load Factor (GWh)
		Oil	Water		
Beckingham	12.3	122.5	25.3	0.1	0.71
Bothamsall	0.7	83	16	0.07	0.47
Cold Hanworth	2.6	23.2	155	0.23	1.6
Corringham	1.5	56.2	3.5	0.03	0.24
Crosby Warren	2	42.4	0	0.02	0.17
East Glentworth	1	13	3.3	0.01	0.08
Egmanton	6.3	48.3	162	0.25	1.8
Farley's Wood	1	15.8	0.17	0.01	0.06
Fiskerton Airfield	0.4	59.5	44	0.09	0.7
Gainsborough	12.3	123.1	10.5	0.08	0.56
Glentworth	1.8	44	24.5	0.06	0.41
Keddington	7.3	16.5	7.2	0.02	0.13
Kirklington	0.4	1.24	5.9	0.009	0.06
Long Clawson	1.2	28.4	52.9	0.09	0.63
Nettleham	0.6	46.7	93.9	0.16	1.1
Rempstone	1.2	8.7	19	0.03	0.22
Saltfleetby	9.1	-	11.6	0.02	0.12
Scampton	0.5	6.8	0.35	0.004	0.03
Scampton North	1	95.5	23	0.08	0.6
South Leverton	0.7	24.9	11.9	0.03	0.21
Stainton	0.9	8.6	0.12	0.005	0.03
Welton	5.1	484	457	0.91	6.36
West Beckingham	N/A	8.6	0.92	0.01	0.04
West Firsby	1.2	18.8	219	0.32	2.26
TOTAL	71			2.64	18.5

5.5.3 Stored heat calculation

A simple stored heat calculation method has been employed to determine heat stored within target strata within each producing oilfield. It takes the following form:

$$Q = M_{dot} * C_p * \Delta T$$ **Equation 5-1: Extractable heat equation**

where M_{dot} represents mass flow rate (kg s^{-1}), C_p represents specific heat capacity (kJ kg^{-1}K) and ΔT represents the change in temperature (°C). Oil and water density values were taken as 0.845 Mg m^{-3} and 1.045 Mg m^{-3}. These values are averaged from oil analysis reports for 21 wells located across 10 separate oilfields. Oil specific heat capacity was approximated to 1.8 kJ kg^{-1} K (Burger et al., 1985); water specific heat capacity was approximated to 3.93 kJ kg^{-1} K (i.e. seawater). ΔT has been varied to determine the available heat for differing resource depletion.

5.5.4 Resource summary

A summary of the geothermal resource available for each field has been summarized in Table 5-3. The data that have been presented here assumes temperatures at 1500 m depth will be 47°C (assuming an average temperature gradient of 31.5°C km^{-1}), and ΔT has been take at 30°C giving an average reinjection temperature of 17°C.

5.6 Discussion

5.6.1 Temperature gradient & data quality

Data across the field have been taken using electric line down-hole logging tools that date from 1955 (Egmanton) to 2007 (Cold Hanworth). These tools were first developed in the 1920's and have evolved dramatically since they were first used. The precision (the closeness of two or more measured values to one another) of these tools and their ability to measure temperature accurately (the closeness of a measured value to a known or standard value) has been discussed by several authors. Wisian et al. (1996) state electric line temperature measurements introduced in the 1960's had a precision of ±0.001°C. Prior to the 1960's, temperatures were measured using thermometers or clock driven recorders. The accuracy of such recorders was noted to be ±2°C (Steingrimsson, 2013). The accuracy of temperature sensors on logging tools that measure temperature as a secondary parameter is unstated, but it is assumed a similar level of accuracy is achieved with these sensors. All logging tools are calibrated prior to and immediately after running down-the-hole (Ball, 2014), in addition to laboratory calibration undertaken prior to taking onsite. As such the results should be of a similar accuracy albeit currently un-quantified. By using two methods to determine temperature gradient in Section 5.5.1, the variation in using a temperature-specific log derived gradient versus using data from all logging tools is 3°C; less than the temperature correction factor of 3.3°C (see Appendix E for data). The 0.3°C variation between the methods gives confidence that the calculated geothermal gradient is relatively robust.

Temperature specific down-hole logs do indicate several wells are not static systems; there is some fluid movement within these wells that causing fluctuation in the temperature. An example log from one oilfield has been reproduced in Figure 5-3. Whilst the fluctuation in absolute temperature can be clearly seen, a geothermal gradient can still be derived. Fluid flow transports heat, increasing it in some areas and decreasing it in others. Elevated temperatures in some areas can be explained by the inflow of warmer water that has risen from greater depths than that penetrated. Conversely, outflow of water into the formation can actively suppress the temperature recorded within the formation. Within these well logs, fluid flow is likely to occur to a degree but it is difficult to quantify given the lack of flow data from down-hole logs. In addition, these logs have been produced within hours of drill circulation ceasing; a time when the well is still recovering from fluids being pumped into the well. Water ingress and egress with respect to temperature suppression are not routinely identified on these oil field well logs. The suppression of temperature caused by this flow is dependent on the velocity of the flow. Kappelmeyer (1979) showed a seepage velocity of 0.3 ma^{-1} across a 1°C temperature variation can alter surface heat flow by 0.024 Wm^{-2}. This equates to a temperature alteration of 150°C at 9.5 km. The velocity of fluid into wells in the assessed oil fields is not known, and as such cannot be estimated. Andrews-Speed et al. (1984) indicate large-scale circulation systems are present in the Western North Sea, penetrating to depths of 1500 m. This flow does depress heat flow across the area, extending to onshore areas. However, a value for this temperature suppression is not offered due to a lack of data on the specific matter. Given the large area over which this circulation is in effect, the view is taken that the relatively small distances over which this flow may affect onshore fields will produce a negligible suppression of temperature. Oil shows will actively flow into the well causing temperature perturbation also.

The level to which circulating fluid perturbation affects the overall BHT is again difficult to quantify. Ultimately the temperature gradient can still be estimated relatively robustly, as the overall general increase in temperature with increasing depth can be taken as the geothermal gradient (as seen on Figure 5-3). Small scale fluctuation is something to be aware of, especially if anomalous data points arise within temperature records.

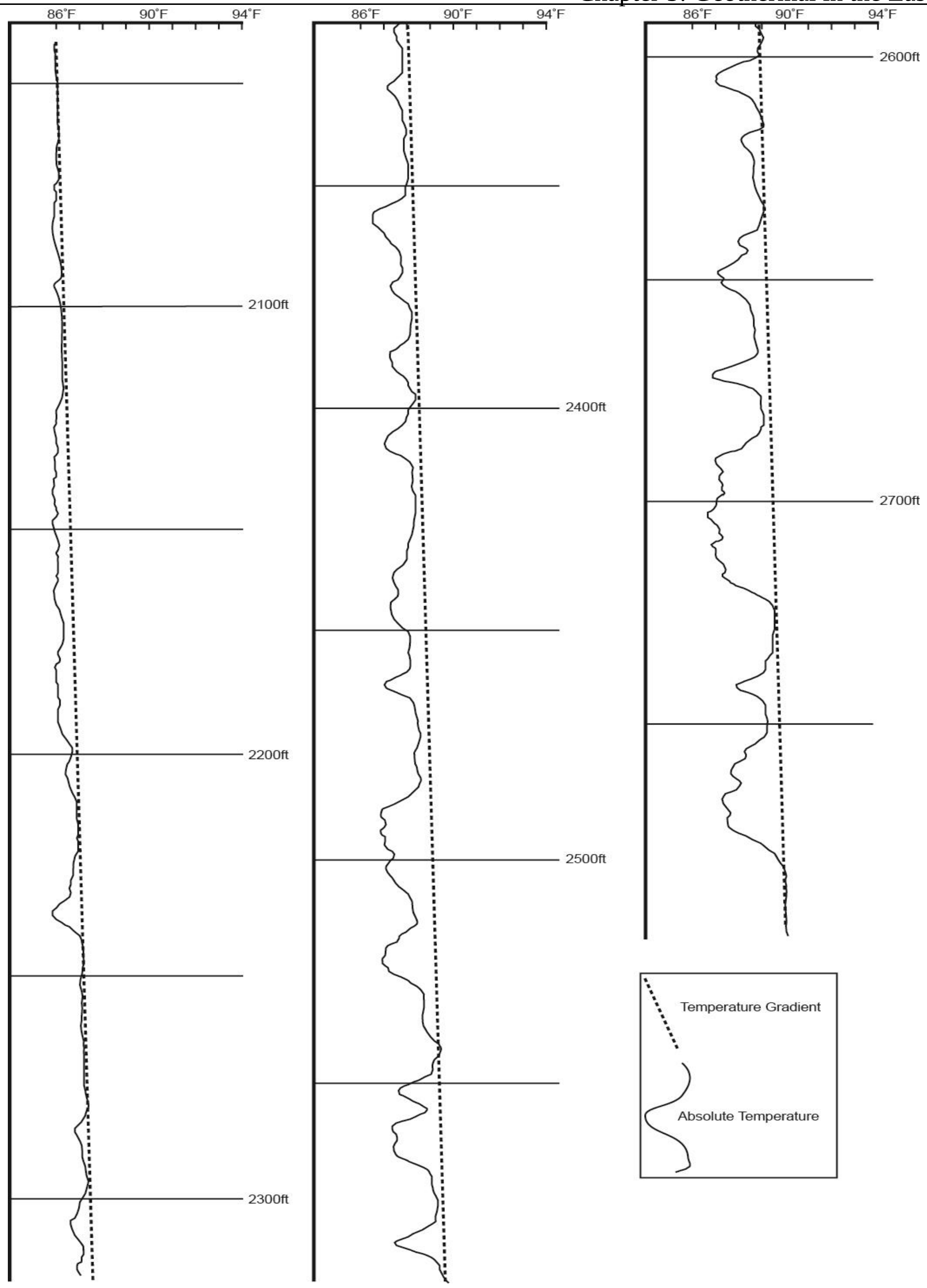


Figure 5-3: Downhole temperature log displaying fluctuations with depth.

5.6.2 Geothermal resource extent

Oilfields across the East Midlands are reducing in capacity: Increasing water cut and a decline in reserves mean that current production rates are reduced. Therefore using peak production rates could be seen as unjustified. However, peak production rates show what the field is capable of producing with regards fluid volume, and is not limited to oil only. Pore spaces within these reservoirs are likely to be occupied by water as a result of oil removal and the fluid volume will therefore still exist. This can, therefore, justify the use of peak production rates within these calculations.

Many wells have been plugged across these fields, requiring drill-outs to bring the well back on-line. Whilst the well may have been plugged with cement, there may also still be well casing or lost drill tools within the well; over-drilling of these wells can become costly if these blockages are encountered. In many cases it would be preferable to drill new wells adjacent to the existing well. However, whilst this will incur an additional expense the ground conditions are already well understood and the requirements for completing the borehole are also well understood. Target formation and depths are known, no additional sampling is required and as such the well can accelerated as a consequence. There will inevitably be some expense associated with the re-completion of many operational wells across all fields, as most will require new well screens with multiple completion zones. In a similar manner to production rate selection, using data from both operational and non-operational wells across the field can ultimately be justified.

The total calculated resource for the oilfields in question is 2.6 MW_t which can be considered a conservative estimate due to the following reasons:

1. The calculated resource does not take into account the additional oilfields for which data was not available for. Over 30 oilfields have been discovered across the East Midlands, and the calculated resource in this study currently only relies on data from 23 of these fields. Regardless of whether the additional fields were major oil / gas producers, the poroperm characteristics within these fields have been favourable enough to allow the field to produce for a length of time and therefore a resource is likely to exist in these areas.
2. The oilfield data that has been utilized has focused on oil-bearing strata only; it does not account for any intervening strata that may be non-oil bearing yet water saturated. These units form a further resource that is yet to be accounted for. In the case of the Welton oilfield, an additional estimate of produced water from such

intervals almost doubles the amount of heat available for extraction (Hirst et al., 2015).

3. For the purposes of this paper, the areal extent of the East Midlands has been defined as the counties that incorporate the oilfields that have been analysed within this study, namely Lincolnshire and Nottinghamshire. The combined area of these counties is approximately 9119 km^2. The area occupied by oilfields, as indicated in Table 5-3, covers a total area of 71 km^2, and therefore represents 0.78% of the East Midlands. Whilst lateral variation in strata does exist in producing bodies, it is not unreasonable to extrapolate the resource identified within the oilfields to a larger area.
4. Reservoir rocks retain good porosity and permeability as a consequence of oil migration into these strata (DECC, 2010). Depending on the timing of migration and the erosion history of the reservoir, it is possible some oil traps have been destroyed during basin inversion and erosion allowing oil to escape to the surface. Retention of any residual porosity and permeability is dependent on the timing of subsequent tectonic phases, but there is the possibility that these units may still retain some enhanced poroperm characteristics.

5.6.3 Application of a geothermal scheme within a producing field

Hot water produced from oilfields only is an undervalued commodity within the oil industry. Currently co-produced water is disposed of or re-injected; the heat contained within extracted water is unused. The additional profit from selling heat from co-produced water could extend the tail-end field life of oilfields. In addition, the infrastructure provided by producing fields reduces the investment required for geothermal scheme to be implemented. The risks usually associated with a new geothermal scheme can be largely reduced when co-managed with an existing oilfield.

5.7 Conclusions

The Carboniferous succession across the East Midlands is laterally heterogeneous making any geothermal resource quantification difficult. Oilfields in the area provide evidence that porosity and permeability can be retained in some areas, and therefore will permit abstraction of oil, water and gas in economic quantities. A first look extractable heat calculation indicates 2.6 MW_t is stored within these fields (given a 30°C depletion in resource). Other non-oil bearing yet water saturated strata exist across the East Midlands that remain unquantified, but are likely to contribute towards a large proportion of available resource. Within the Welton field, taking account of these strata almost doubles the amount of water available for abstraction.

Currently extracted water across the fields is unused, being either disposed of or re-injected. The sale of heat contained within this warm water can provide additional income to extend the tail end lifespan of the oilfield in question. In addition, re-injection of cooled water can increase the recovery factor of the reservoir. Cooled water has a higher viscosity and hence lower mobility ratio contrast with oil than would hot water, and as such could “sweep” remaining oil reserves out of the reservoir further improving the economics of extraction.

5.8 References

Adams, C. A., Gluyas, J. G., and Mathias, S. A., 2010, Application of hydrogeological parameters for evaluating the thermal resource potential of deep groundwater systems, BHS Third International Conference : Role of hydrology in managing consequences of a changing global environment.: Newcastle upon Tyne, British Hydrological Society.

Andrews-Speed, C. P., Oxburgh, E. R., and Cooper, B. A., 1984, Temperatures and depth-dependant heat flow in western North Sea: The American Association of Petroleum Geologists, v. 68, no. 11, p. 1764-1781.

Atkins, 2013, Deep Geothermal Review Study Final Report: Department of Energy and Climate Change (DECC).

Bailey, R. J., 2003, The West Firsby Oilfield, Development Licence 003, Lincolnshire: Geological Society, London, Memoirs, v. 20, no. 1, p. 921-926.

Ball, R., 2014, The accuracy of downhole logging tools (Pers. Comm).

Banks, D., 2008, An Introduction to Thermogeology: Ground Source Heating and Cooling, Newcastle-Upon-Tyne: Blackwell Publishing.

Burger, J., Sourieau, P., and Combarnous, M., 1985, Thermal Methods of Oil Recovery, Editions Technip, Paris.

Busby, J., 2010, Geothermal Prospects in the United Kingdom, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.

Craig, J., Gluyas, J. G., Laing, C., and Schofield, P., 2013, Hardstoft - Britain's First Oil Field: Oil-Industry History, v. 14, no. 1, p. 97-116.

Crampon, N., Custodio, E., and Downing, R. A., 1996, The hydrogeology of Western Europe: a basic framework: Quarterly Journal of Engineering Geology and Hydrogeology, v. 29, no. 2, p. 163-180.

DECC, 2010, The Hydrocarbon Prospectivity of Britain's Onshore Basins, Promote UK 2011, p. 86.

-, 2013, Energy Consumption in the UK (2013).

Directive 2009/28/EC, 2009, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

Downing, R. A., and Gray, D. A., 1986, Geothermal Energy: The potential in the United Kingdom London, HMSO.

Fraser, A. J., and Gawthorpe, R. L., 1990, Tectono-stratigraphic development and hydrocarbon habitat of the Carboniferous in northern England: Geological Society, London, Special Publications, v. 55, no. 1, p. 49-86.

Glennie, K. W., 2005, Regional tectonics in relation to Permo-Carboniferous hydrocarbon potential, Southern North Sea Basin *in* Collinson, J. D., Evans, D. J., Holliday, D. W., and Jones, N. S., eds., Carboniferous Hydrocarbon Geology: The southern North Sea and surrounding onshore areas, Volume 7, Yorkshire Geological Society, p. 12.

Gluyas, J. G., and Hichens, H. M., 2003, United Kingdom Oil and Gas Fields Commemorative Millennium Volume: Geological Society, London, Memoirs, v. 20.

Hirst, C. M., and Gluyas, J. G., 2015, The Geothermal Potential Held within Carboniferous Sediments of the East Midlands: A New Estimation Based on Oilfield Data, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Hirst, C. M., Gluyas, J. G., and Mathias, S. A., 2015, The late field life of the East Midlands Petroleum Province; a new geothermal prospect?: Quarterly Journal of Engineering Geology and Hydrogeology, v. 48, no. 2, p. 104-114.

Hodge, T., 2003, The Saltfleetby Field, Block L 47/16, Licence PEDL 005, Onshore UK: Geological Society, London, Memoirs, v. 20, no. 1, p. 911-919.

Holliday, D. W., 1986, Devonian and Carboniferous Basins, *in* Downing, R. A., and Gray, D. A., eds., Geothermal Energy: The Potential in the United Kingdom: London, HMSO, p. 27.

Kappelmeyer, O., 1979, Implications of heat flow studies for geothermal energy prospects., *in* Cermak, V., and Rybach, L. O., eds., Terrestrial Heat Flow in Europe, Springer-Verlag, Berlin, p. 126-135.

Majorowicz, J., Safanda, J., and Skinner, W., 2004, Past surface temperature changes as derived from continental temperature logs - Canadian and some global examples of a new tool in climate change studies, *in* Dmowska, R., ed., Advances In Geophysics, Volume 47, Elsevier, p. 123.

Manning, D. A. C., Younger, P. L., Smith, F. W., Jones, J. M., Dufton, D. J., and Diskin, S., 2007, A deep geothermal exploration well at Eastgate, Weardale, UK: a novel exploration concept for low-enthalpy resources: Journal of the Geological Society, v. 164, no. 2, p. 371-382.

Met Office, 2014, UK mapped climate averages: Annual soil temperature at 30 cm depth, http://www.metoffice.gov.uk/public/weather/climate/.

Rollin, K. E., Kirby, G. A., Rowley, W. J., and Buckley, D. K., 1995, Atlas of Geothermal Resources in Europe: UK Revision: British Geological Survey, Regional Geophysics Series, Technical Report WK/95/07.

Smith, I. F., 1986, Mesozoic Basins, *in* Downing, R. A., and Gray, D. A., eds., Geothermal Energy: The Potential in the United Kingdom, HMSO, p. 42.

Steingrimsson, B., 2013, Geothermal well logging: temperature and pressure logs, Short Course V on Conceptual Modelling of Geothermal Systems: Santa Tecla, El Salvador.

Underhill, J. R., 2003, The tectonic and stratigraphic framework of the United Kingdom's oil and gas fields: Geological Society, London, Memoirs, v. 20, no. 1, p. 17-59.

United Nations, 1997, Kyoto Protocol to the United Nations Framework Convention on Climate Change.

Ward, J., Chan, A., and Ramsay, B., 2003, The Hatfield Moors and Hatfield West Gas (Storage) Fields, South Yorkshire: Geological Society, London, Memoirs, v. 20, no. 1, p. 903-910.

Waters, C. N., and Davies, S. J., 2006, Carboniferous: extensional basins, advancing deltas and coal swamps., *in* Brenchley, P. J., and Rawson, P. F., eds., The geology of England and Wales: London, Geological Society of London, p. 173-223.

Westaway, R., and Younger, P. L., 2013, Accounting for palaeoclimate and topography: A rigorous approach to correction of the British geothermal dataset: Geothermics, v. 48, no. 0, p. 31-51.

Wisian, K. W., Blackwell, D., Bellani, S., Henfling, J. A., Normann, R. A., Lysne, P. C., Förster, A., and Schrötter, J., 1996, How hot is it? A comparison of advanced technology temperature logging systems: TRANSACTIONS-Geothermal Resources Council v. 20, p. 427-434.

Younger, P. L., Gluyas, J. G., and Stephens, W. E., 2012, Development of deep geothermal energy resources in the UK: Proceedings of the Institution of Civil Engineers - Energy, v. 165, no. 1, p. 19-32.

Chapter 6:

The Cheshire Basin – using an offshore analogue to better constrain onshore geothermal aquifer parameters

Parts of this Chapter has been published within the Proceedings of the World Geothermal Congress 2015: (Hirst et al., 2015a)

6.1 Introduction

The UK's 2008 Climate Change Act committed the country to reduce greenhouse gas emissions by at least 80% (compared with the 1990 base level) by 2050. Commitment to the Climate Change Act is a huge undertaking that requires radical change to the way in which the country uses energy and captures emissions. No single technology can deliver the 80% reduction target (IPCC, 2014) but the use of low enthalpy geothermal energy could make an important contribution. Improvements in drilling technology and development of binary cycle power generation plants has increased global geothermal availability (Bertani, 2009) by improving the economic case for the exploitation of low-mid enthalpy resources (i.e. those having temperatures of <150ºC). Where temperatures permit, power generation as well as heat generation can be produced from the resource. In lower temperature settings heat only projects are a viable way to exploit a geothermal resource.

Geothermal prospecting requires searching for suitable thicknesses of permeable formations at sufficient depth to yield suitable temperatures. The possibility of developing geothermal energy is enhanced in areas where the geothermal gradient is elevated above the UK average of 26°C km^{-1} (Busby, 2014). Smith (1986) state a minimum viable temperature of 40°C and flow rates of 2160-4320 m^3 d^{-1} are required for a viable resource, although more recently it has been shown that flow rates of 860 m^3 d^{-1} are sustainable (Adams et al., 2010). In general terms groundwater within basin systems needs to be tapped at depths of 1 to 1.5 km or 2 to 3 km to produce water temperatures in excess of 40°C and 60°C respectively. Finding strata that are sufficiently permeable to support the abstraction necessary to supply the intended amount of heat can be a major risk for geothermal projects, particularly since reduction of reservoir permeability often correlates with increased reservoir temperature because most diagenetic reactions that reduce porosity and permeability are promoted by elevated temperatures. The risk of not finding the aforementioned flowing strata can be reduced by assessing the deep onshore well data that exist. However, difficulty arises given the sparsity of such data. Deep well data, or lack of, forms a major barrier in de-risking geothermal projects. Without a concise understanding of the subsurface, there is a high risk that a resource may not be found. The financial burden of a failed first project is one that is difficult for the geothermal industry to shoulder. Creating a partnership with the petroleum industry can have major benefits in geothermal development as a comprehensive understanding of the petroleum system is already well understood. With both the hydrocarbon industry and geothermal industry being extractive industries, both require a similar understanding and approach prior to exploitation. To that end, reservoir analogues from the petroleum industry can add some confidence; for example permeability data from sandstone and limestone intervals which are important oil and gas producers in the East Midlands (Hirst et al., 2015b) and the North Sea (Adams et al., 2010) can be used as analogues in the areas considered for geothermal exploration but for which few data exist.

6.2 Rationale

Though low-enthalpy in nature, the UK's geothermal resource base is relatively large. Busby (2010) estimated the technically usable heat resource in the four deep sedimentary basins in the UK and two in Northern Ireland to be approximately $300x10^{18}$ Joules. This value is based upon extraction of hot water alone. The magnitude of the resource becomes apparent when you consider that the current UK yearly energy 'bill' amounts to approximately $8x10^{18}$ Joules of which 45% is used for domestic, industrial and service sector heating (DECC, 2013a), and so if this resource play could be developed commercially, the size of the resource would not limit growth.

One of the prospective areas for development of geothermal energy is the Cheshire Basin located in the NW Midlands of England (as depicted on Figure 6-1). The cities of Liverpool and Manchester are on its northern margin with a total population of approximately 5 million, and an area just over 4000 km^2 (Greater Manchester, Merseyside, Cheshire; UK Office for National Statistics).

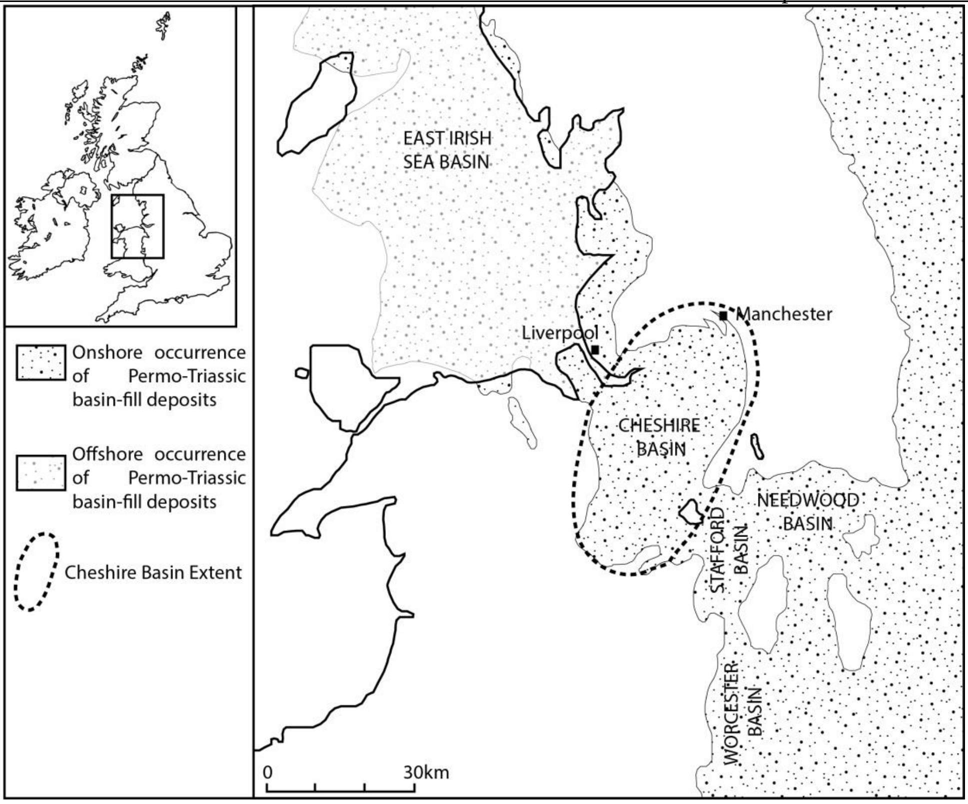


Figure 6-1: Cheshire Basin and East Irish Sea Basin extent (Plant et al., 1999).

A recent Deep Geothermal Review Study of the UK (Atkins, 2013) built on previous geothermal resource analyses by Downing and Gray (1986), Rollin et al. (1995), Busby (2010) and Busby (2014). All highlight the basin as being a probable heat reserve located in an area that has a heat demand as depicted on Figure 6-2. Figure 6-3 provides a breakdown of the share of heat use across the approximate area of the basin. Residential, industrial, transport and retail sectors are the largest users of heat.

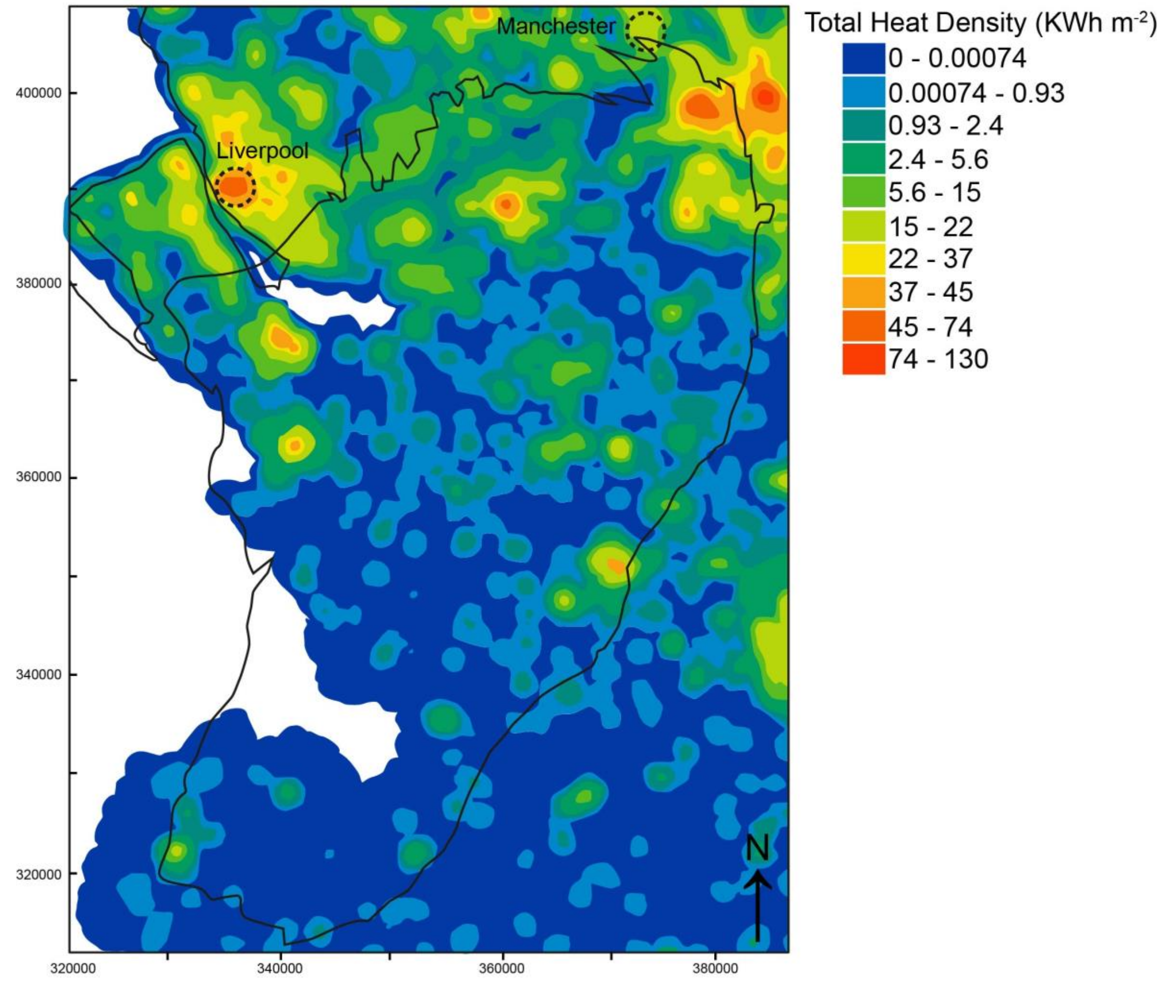


Figure 6-2: Total heat demand across the Cheshire Basin (black outline) area (The Centre for Sustainable Energy, 2012).

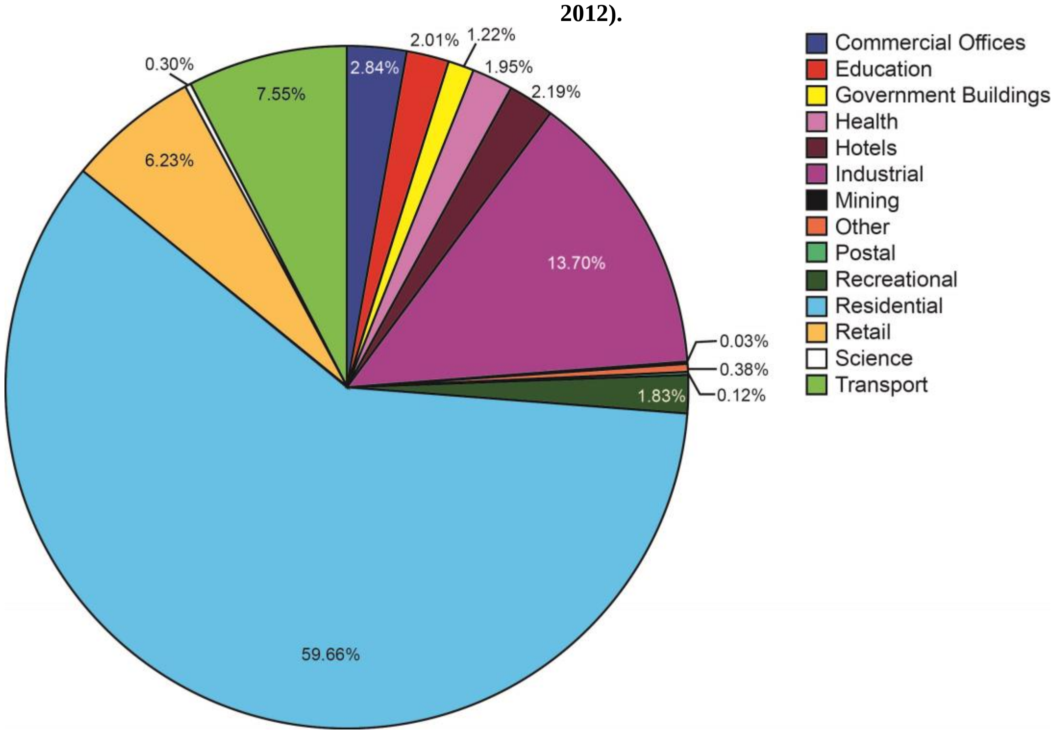


Figure 6-3: Pie chart of Heat Demand by sector within the Cheshire Basin (The Centre for Sustainable Energy, 2012).

The basin is comprised of Permo-Triassic sediments extending to at least 4.5 km depth, underlain for the most part by Carboniferous strata. The geothermal resource value for the basin was previously quantified at 74.7 EJ; 36.2 EJ from the Triassic Sherwood Sandstone Group and 38.5 EJ from the Permian Collyhurst Sandstone (Busby, 2014; Rollin et al., 1995). The estimation was based on the calculated volume of rock likely to be at a temperature >40°C. The geothermal gradient across the basin has recently been revised to 27°C km^{-1} (Busby, 2014) meaning temperatures of 40°C will be obtained at depths of ~1.5 km. Previous resource estimates by Downing and Gray, (1986) and Rollin et al., (1995) stated 5-10 D m transmissivity would be available from reservoir sandstones within the basin (intrinsic permeability of $9.9x10^{-12}$ m^3, Busby, 2014), equating to a permeability of 100 mD over a 100 m reservoir section. The resource estimate is based on very limited data; only two wells penetrate the full thickness of Permo-Triassic sediments within the Cheshire Basin. The Cheshire Basin and East Irish Sea Basin (henceforth referred to as the EISB) are both part of the same Permo-Triassic rift basin system. The underlying Carboniferous Coal Measures and Namurian shales are gas and oil prone; the EISB has been exploited for its oil and gas deposits since the discovery of the Morecambe Field in 1974 (Colter, 1997). In contrast whilst there have been some oil and gas shows, no commercial discoveries of petroleum have been located in the onshore Cheshire Basin (Mikkelsen and Floodpage, 1997) indicating there is either lateral heterogeneity in the underlying Carboniferous source rocks (Namurian shales), a disparity in burial and source rock maturation history, a lack of trapping structures or a combination of all the above. We know from many wells in the EISB that the strata are permeable, capable of flowing at rates of at least 864 m^3 d^{-1}; a figure comparable with that achieved by the UK’s single low enthalpy geothermal scheme in Southampton. The Cheshire Permo-Triassic rocks are themselves excellent aquifers and have been exploited extensively, particularly in the Peckforton Hills. What is not well constrained for the Cheshire Basin are values of porosity and permeability (and, therefore, transmissivity), the likely storage volume of exploitable reservoirs and the segmented nature of the basin. Transmissivity data for the Cheshire Basin is sparse as there are insufficient deep well data across the Cheshire Basin, but was estimated at being a minimum of 10 D m (Smith, 1986). A value of 5 D m was stated as the ‘absolute minimum’ required for geothermal resource calculations by Rollin et al. (1995). The field structures seen in the EISB are broadly similar to those seen across the Cheshire Basin and it is reasoned that the size and volume of transmissive blocks will be broadly similar across both basins.

6.3 Aims & Objectives

The EISB is linked to the Cheshire Basin and displays a similar geological succession. Access to data pertaining to the oil and gas fields located within the EISB can be considered as potential analogue data. As such it may be possible to produce a more concise understanding and quantification regarding the aquifer properties of strata underlying the Cheshire Basin if this information is drawn upon. In addition reservoir studies of the Sherwood Sandstone Group are far more comprehensive for offshore sections providing important information on heterogeneities that exist. Chapter 6 aims to assess the porosity and permeability data for offshore reservoirs to better constrain likely porosity and permeability for the onshore equivalents, leading to a better understanding of likely transmissivity and ultimately flow rates. These data will be obtained from the analogous EISB.

The key objectives of this work were as follows:

- Identify reservoir horizons within each basin.
- Determine the depositional environment of the EISB and the Cheshire Basin to identify the lateral persistence of potential permeability barriers.
- Compare the burial and exhumation history of the EISB and Cheshire Basin to determine if they are of comparable magnitude.
- Identify and compare the main structural patterns within each basin including persistence and spacing of faults. From these data produce a conceptual model of connected volumes and potential compartmentalisation of reservoirs.
- Determine diagenetic histories of both basins to identify potential permeability barriers, their persistence and the impact this has on compartmentalisation. This includes fault-related diagenesis.
- Identify offshore porosity and permeability trends and compare with the limited onshore dataset.
- Using these trends determine likely permeability within suitable reservoir sections at their deepest point, calculate transmissivity and determine if these values support the original transmissivity estimate.

6.4 Methods

6.4.1 Literature Review

A large part of this chapter is based on the outcome of a major comparative review of the Cheshire Basin and the EISB. The establishment of the key similarities and differences between the two study areas and has allowed a decision to be made on how analogous the EISB is to the Cheshire Basin. The literature-based review has been undertaken in the following order:

- Review and comparison of the general paleogeography during four major geological periods (Carboniferous, Permian, Triassic, Jurassic) across both basins to understand the general environment of deposition.
- A detailed look at the geological successions throughout the Carboniferous, Permian, Triassic and Jurassic, focusing on facies variation and correlation across both basins.
- An assessment of the burial and exhumation history of both basins to understand any secondary diagenetic processes that may have occurred and could potentially limit the aquifer properties of any target reservoirs. Any maturation history is included within this section.
- An assessment of the tectonic structures present across both basins, including data pertaining to fault spacing, permeability and transmissivity.
- A summary of porosity, permeability, transmissivity and temperature data that are available across both basins.

6.4.2 Porosity & Permeability Measures

Data are presented for porosity and permeability. These data have been taken from Plant et al. (1999), Rollin et al. (1995), Bloomfield et al. (2006), British Geological Survey (1997) and routine core analysis spreadsheets supplied by ENI UK Ltd (ENI) for southern EISB fields (Douglas, Hamilton, Hamilton North, Hamilton East, Lennox, exploration wells); various methods of measurement have been used. Porosity published by Plant et al. (1999) and Rollin et al. (1995) are noted to be log-derived. It is not specified what type of porosity, or the method of measurement, has been used in data presented by the British Geological Survey (1997). Bloomfield et al. (2006) state their porosity data was obtained using a “standard liquid re-saturation”, whilst horizontal permeability data was obtained using nitrogen under steady state conditions. Offshore data from ENI has been obtained through routine core analysis (helium porosity, horizontal air permeability).

Hydraulic conductivity measurements (recorded in m d^{-1}) were presented by the British Geological Survey (1997) and have subsequently been converted to intrinsic permeability (mD) to allow a comparison of values, related as per Equation 6-1. The conversion is based on the equations of Darcy's Law (defined in Chapter 2) and was undertaken using the conversion table (Table 6-1). These assume the aquifer analysed is granular, homogenous, isotropic and of infinite extent.

- $K = k\rho g/\mu$

K= Hydraulic conductivity m s^{-1} **k** = Intrinsic Permeability m^2 **ρ** = density (kg m^{-3}) **g** = acceleration due to gravity (m s^{-2}) **μ** = dynamic viscosity of the liquid (kg m^{-1} s^{-1})

Equation 6-1: Hydraulic conductivity calculation based on Darcy's Law

It is noted that porosity derived from geophysical logs are not directly comparable to helium porosity as the latter measurement method takes into account micro-porosity; log-derived porosity does not take this into account. Variations will, therefore, exist in these data. However, at this stage of geothermal assessment it is considered reasonable to use these data to improve the total number of data points to allow a more robust estimate of porosity at depth.

6.4.3 Temperature Correction

Borehole Bottom Hole Temperatures (BHTs) from the EISB are uncorrected as the necessary information required to correct such temperatures using the Horner correction are not available (Deming, 1989); they do not represent true formation temperature and just over 1/10th of wells have the necessary information required to carry out the correction. During the drilling of a borehole, circulated drill fluid invades the surrounding formation causing temperatures to be suppressed. In addition, prior to any logging operations the well is circulated and flushed clean with water typically at a lower temperature than that of the surrounding formation (Bonté et al., 2012). Busby (2014) has presented a corrected geothermal gradient within the Cheshire Basin of 27°C km^{-1}. In this instance the derived offshore estimate of temperature gradient will be considered conservative.

6.4.4 Transmissivity Estimate

Transmissivity has been calculated based on Equation 6-2:

$$T = k * b$$

T = Transmissivity (mD m) k = Intrinsic permeability (mD) b = Thickness (m)

Equation 6-2: Transmissivity calculation

Calculation of transmissivity across faults has been defined by Beach et al. (1997), noted in Equation 6-3:

$T = k * fzt$	T = Transmissivity (mD m) k = Fault zone permeability (mD) fzt = Fault zone thickness (m)	**Equation 6-3: Method of estimating fault transmissivity after Beach et al. (1997)**

Conversion between the various units used within the Chapter has been done using Table 6-1.

6.4.5 Fault Width

To determine likely fault width, the relationship derived by Beach et al. (1997) has been reproduced in Figure 6-4. The line of best fit has been used to determine likely fault width which has then been used within calculation of fault transmissibility.

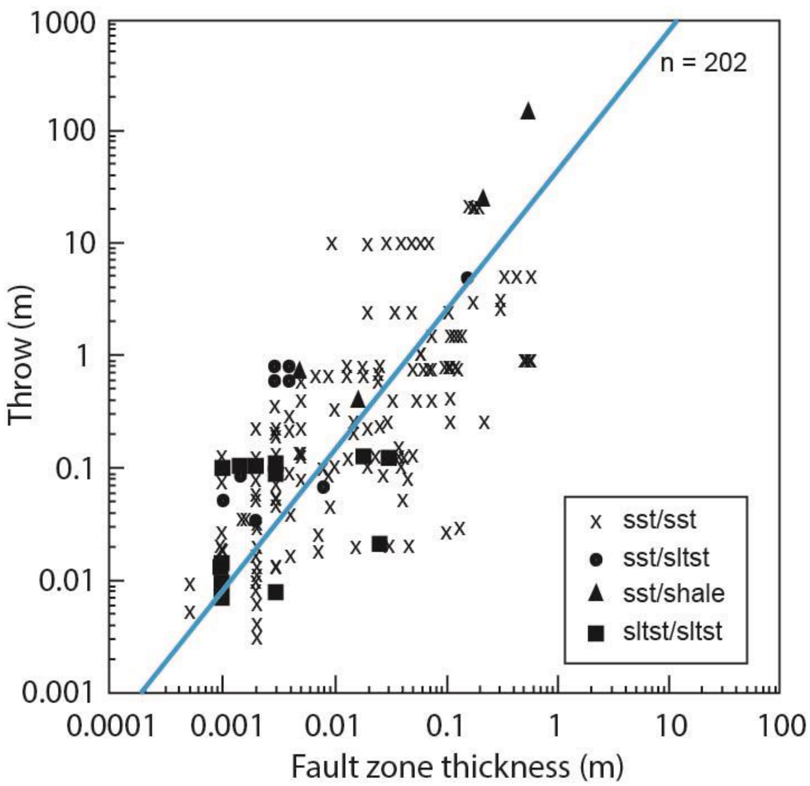


Figure 6-4: Fault throw versus fault zone thickness measured in Permo-Triassic sandstones of NW England, including the Cheshire Basin (Beach et al., 1997).

Measured throw on faults across the Cheshire Basin have been related to fault zone thickness using this figure.

Table 6-1: Conversion between units used for hydrogeological assessment of the Cheshire Basin and EISB, with parameters producing 5 and 10 D m highlighted.

D	mD	Permeability m^2	Hydraulic Conductivity $m\ d^{-1}$	Aquifer thickness = 1 m				Aquifer thickness = 10 m				Aquifer thickness = 100 m			
				T D m	T mD m	T $m^2\ d^{-1}$	T m^3	T D m	T mD m	T $m^2\ d^{-1}$	T m^3	T D m	T mD m	T $m^2\ d^{-1}$	T m^3
0.0001	0.1	9.87E-17	0.0001	0.0001	0.1	0.0001	9.87E-17	0.001	1	0.001	9.9E-16	0.01	10	0.01	9.9E-15
0.001	1	9.87E-16	0.0007	0.001	1	0.001	9.87E-16	0.01	10	0.01	9.9E-15	0.1	100	0.07	9.9E-14
0.002	2	1.97E-15	0.0015	0.002	2	0.001	1.97E-15	0.02	20	0.01	2E-14	0.2	200	0.15	2E-13
0.005	5	4.94E-15	0.0037	0.005	5	0.004	4.94E-15	0.05	50	0.04	4.9E-14	0.5	500	0.37	4.9E-13
0.01	10	9.87E-15	0.0074	0.01	10	0.01	9.87E-15	0.1	100	0.07	9.9E-14	1	1000	0.74	9.9E-13
0.02	20	1.97E-14	0.0148	0.02	20	0.01	1.97E-14	0.2	200	0.15	2E-13	2	2000	1.48	2E-12
0.05	50	4.94E-14	0.037	0.05	50	0.04	4.94E-14	0.5	500	0.37	4.9E-13	5	5000	3.71	4.9E-12
0.1	100	9.87E-14	0.074	0.1	100	0.07	9.87E-14	1	1000	0.74	9.9E-13	10	10000	7.42	9.9E-12
0.25	250	2.47E-13	0.19	0.25	250	0.19	2.47E-13	2.5	2500	1.86	2.5E-12	25	25000	18.55	2.5E-11
0.5	500	4.94E-13	0.37	0.5	500	0.37	4.94E-13	5	5000	3.71	4.9E-12	50	50000	37.10	4.9E-11
1	1000	9.87E-13	0.74	1	1000	0.74	9.87E-13	10	10000	7.42	9.9E-12	100	100000	74.20	9.9E-11
2	2000	1.97E-12	1.48	2	2000	1.48	1.97E-12	20	20000	14.84	2E-11	200	200000	148.40	2E-10
3	3000	2.96E-12	2.23	3	3000	2.23	2.96E-12	30	30000	22.26	3E-11	300	300000	222.60	3E-10
4	4000	3.95E-12	2.97	4	4000	2.97	3.95E-12	40	40000	29.68	3.9E-11	400	400000	296.80	3.9E-10
5	5000	4.94E-12	3.71	5	5000	3.71	4.94E-12	50	50000	37.10	4.9E-11	500	500000	371.0	4.9E-10
10	10000	9.87E-12	7.42	10	10000	7.42	9.87E-12	100	100000	74.20	9.9E-11	1000	1000000	742.0	9.9E-10

6.5 Study Area Overview

An overview of the geological linkage between the Cheshire Basin and the EISB is presented in on the geological map in Figure 6-5. The Triassic and Permian strata that make up the main basin fill can be clearly seen, surrounded by predominantly Carboniferous-age deposits.

The basin history of Cheshire and the EISB requires an understanding to determine not only the distribution of potential reservoirs, but also to aid determination of the hydrogeological properties these reservoirs may display in particular locations. There are likely variations in the distribution of facies across both basins that will affect their reservoir prospectivity. Large reserves of oil and gas exist in the EISB (and have been exploited) yet no exploitable reserves have been discovered in Cheshire suggesting there are depositional variations that affect source rock distribution. However, it does not mean that these same reservoirs are not found within the Cheshire Basin; they are likely to be present and water-bearing. The porosity and permeability of potential reservoirs may display lateral variation that could also, in part, be controlled by depositional environment variation.

Attempts at correlating the stratigraphy between each basin has been attempted by several authors, the culmination of which is presented on Figure 6-6. Within the Cheshire Basin the Triassic Sherwood Sandstone Group and Permian Collyhurst Sandstone form the target geothermal horizons, having already being proven as large volume water-bearing horizons. Within the EISB the target reservoir for oil and gas exploitation is primarily the Sherwood Sandstone Group also (specifically the Ormskirk/Helsby Sandstone). The Collyhurst Sandstone forms a secondary target that is not widely exploited but is seen as a potential reservoir. It is these strata that form the focus of this assessment and will be described within the following section.

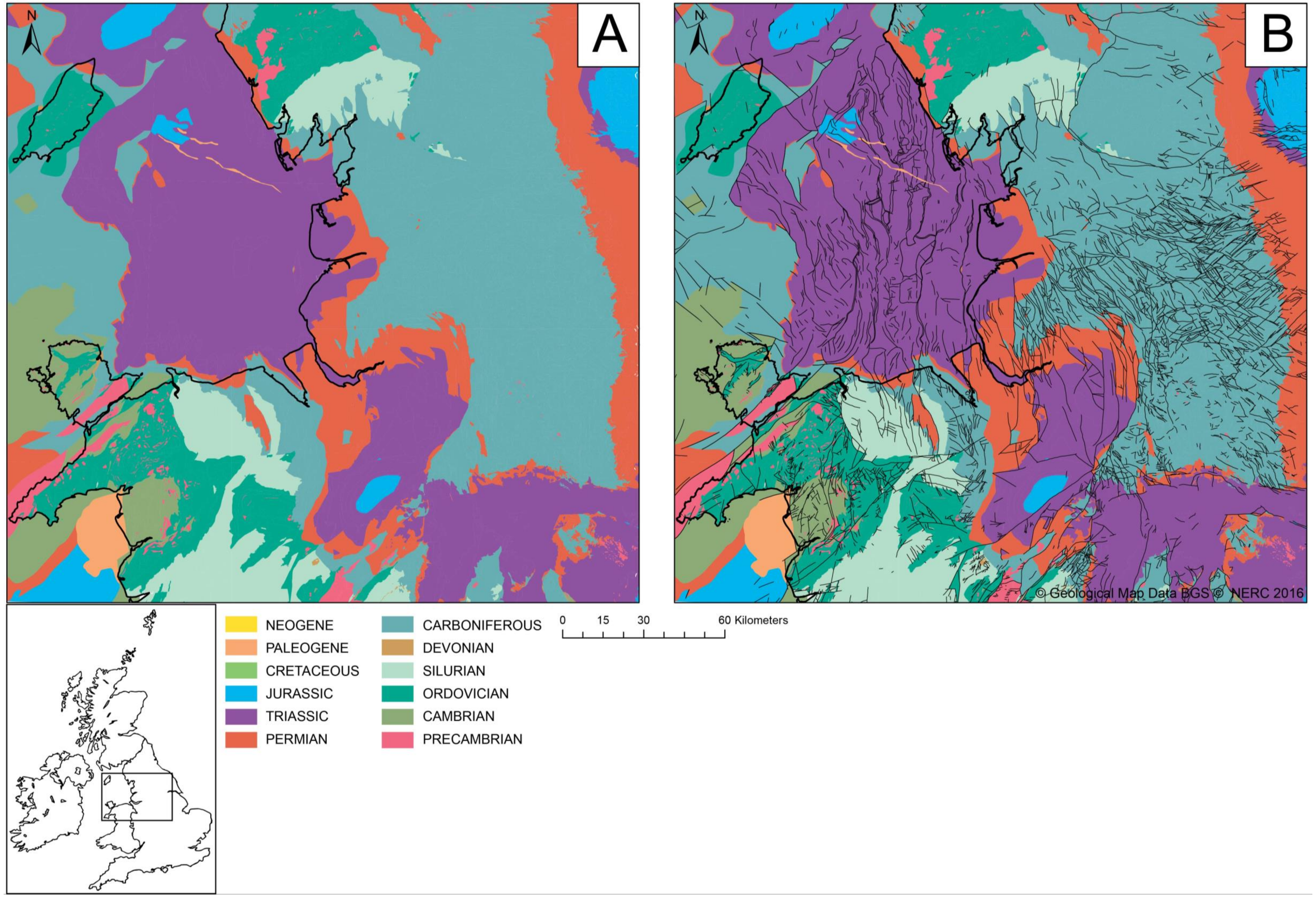


Figure 6-5 A) Geological overview map of the EISB and Cheshire Basin. B) Showing the main distribution of fault structures across the EISB and Cheshire Basin.

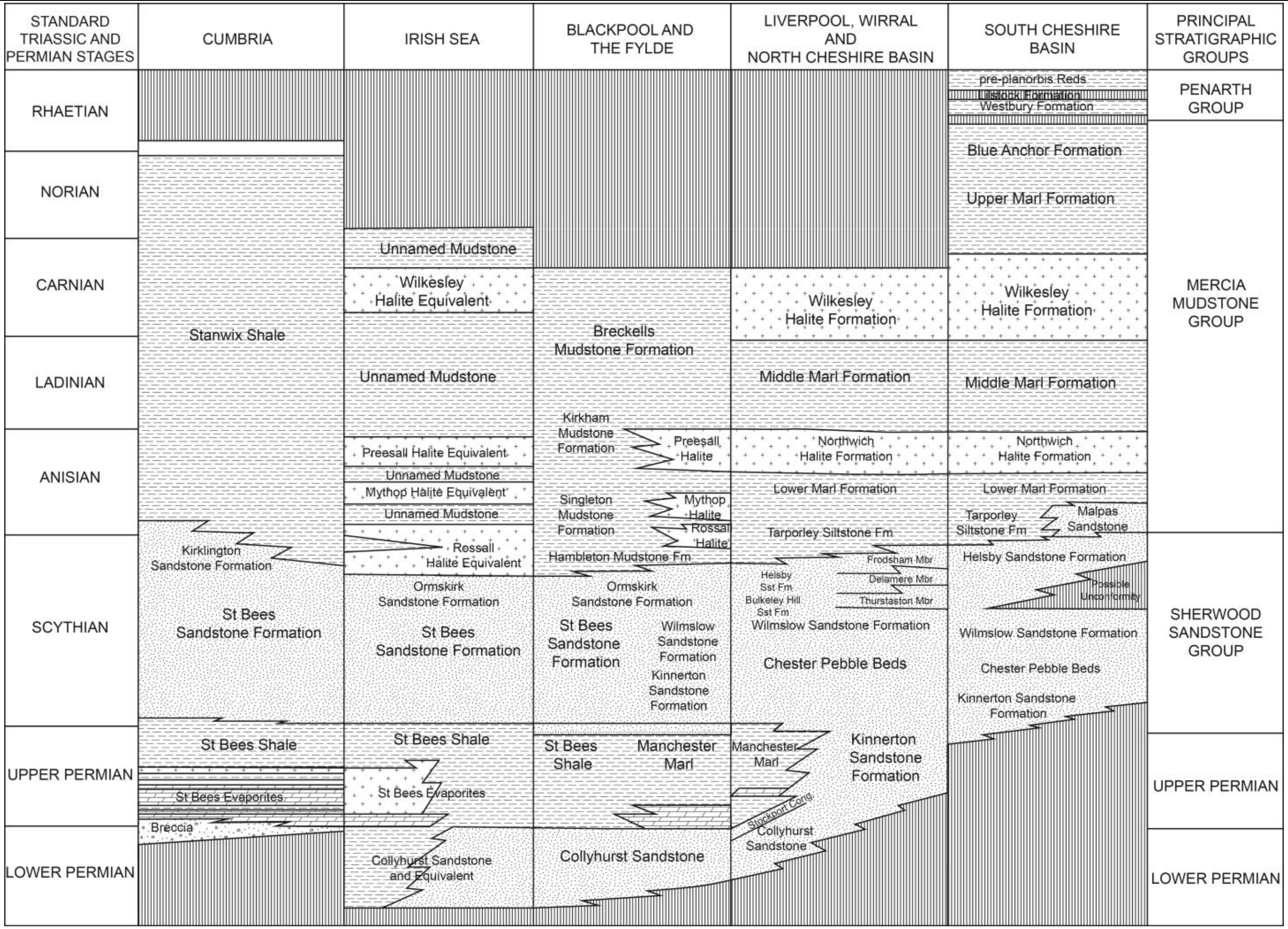


Figure 6-6: Correlated Triassic and Permian stratigraphy across the Cheshire Basin and EISB (Meadows and Beach, 1993).

6.5.1 Basin Overview: The Cheshire Basin

As shown in Figure 6-7, the Cheshire Basin forms part of a complex Permo-Triassic rift structure bounded by faults and filled with thick (>4500 m) deposits of Triassic strata (Sherwood Sandstone Group) and Permian strata (Collyhurst Sandstone) sediments. Also annotated on Figure 6-7 are wells penetrating >500 mBGL.

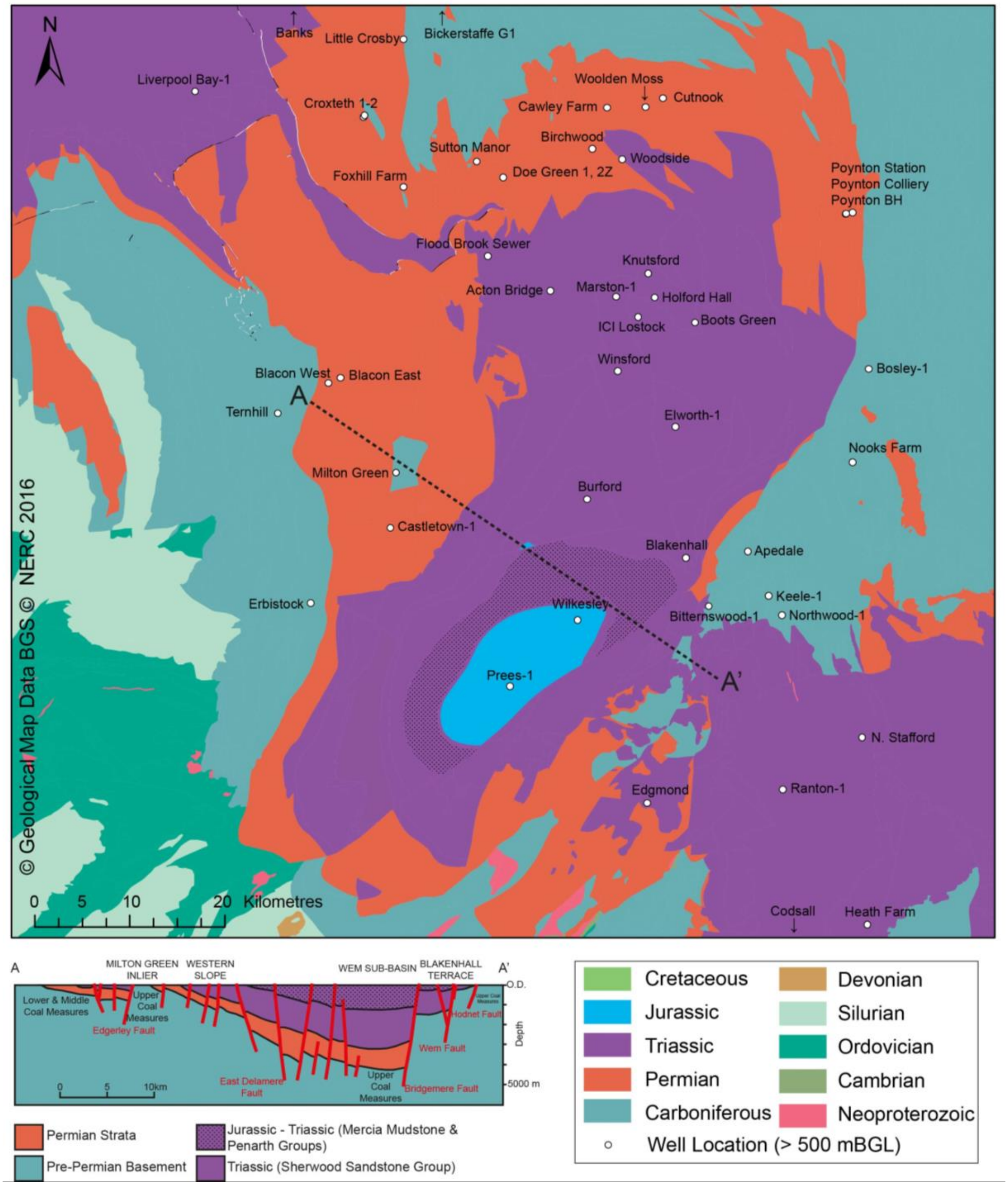


Figure 6-7: Geological Map and Cross Section of the Cheshire Basin (Plant et al., 1999).

An isopach map indicating the base of the Permian sediments has been presented in Figure 6-8, highlighting the asymmetry of the basin, and also the location of the deepest potential aquifer (Plant et al., 1999).

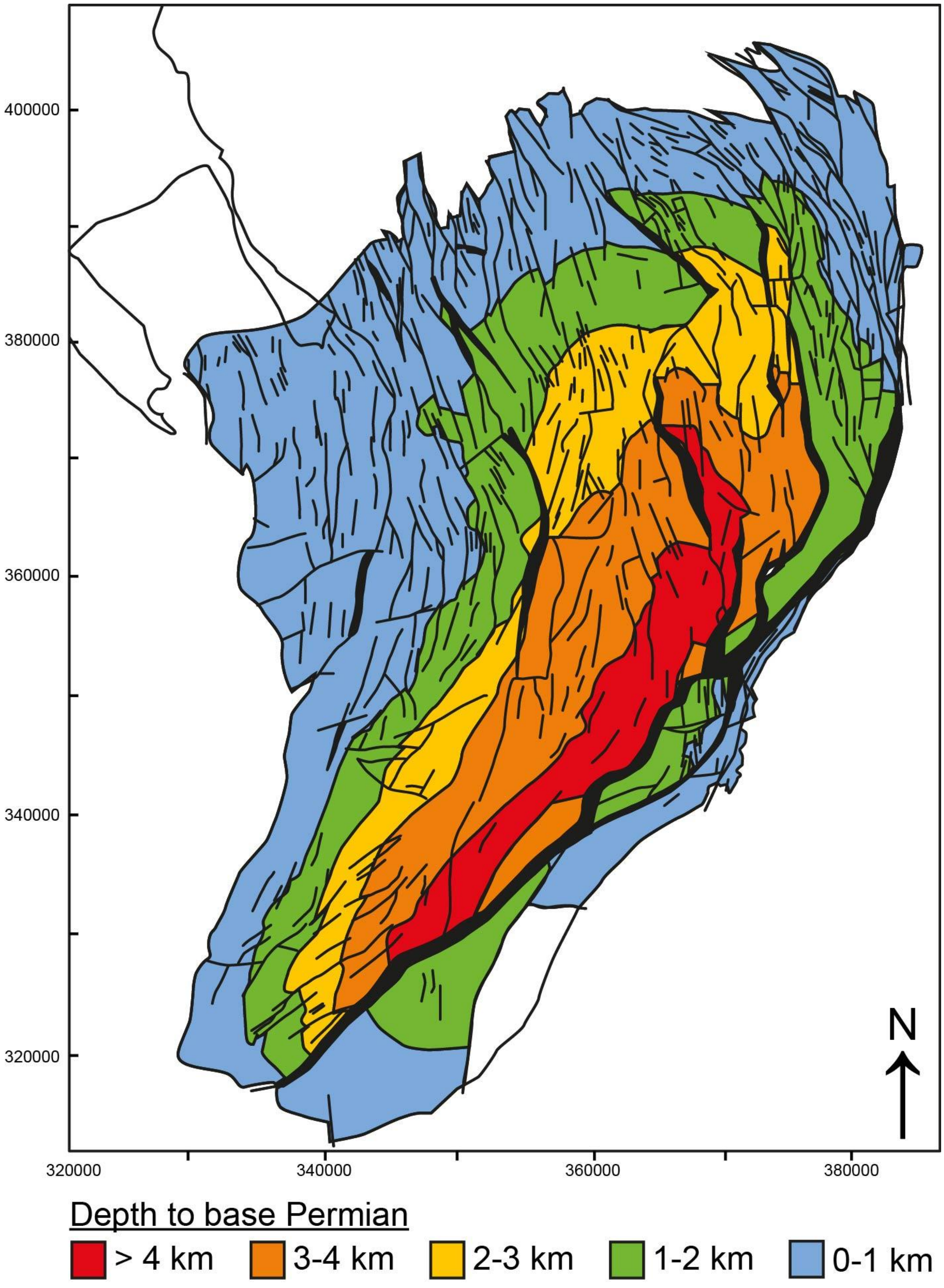


Figure 6-8: Depth contours to the base of the Permo-Triassic (Plant et al., 1999). It includes major faults that have been recognised at the base of the Permo-Triassic also (Chadwick, 1997).

The majority of the basin is overlain by the Triassic Mercia Mudstone Group (MMG) and it is bounded by the Carboniferous rocks of the Pennines to the east and of the Wrexham Coalfield to the west. These sediments rest unconformably upon folded Carboniferous strata that in turn lie on a Lower Palaeozoic basement. The Cheshire Basin hosts a range of resources including vast reserves of halite that helped to establish the UK chemical industry during the 19th century. The basin contains large Permo-Triassic aquifers that are important for potable water supply and contains industrial aggregate minerals and sedimentary-copper type base metal mineralisation. These were formerly worked at Alderley Edge, Grinshill and in the Peckforton Hills from the Bronze Age until the early 20th century. The Triassic Sherwood Sandstone Group is a major aquifer in Northwest England. The Sherwood Sandstone Group is 1615 m thick in the Knutsford-1 borehole and 957 m thick in the Prees-1 Borehole (Evans et al., 1993). Borehole yields are variable with rare failures (i.e. dry boreholes). Yields of 4320 m^3 d^{-1} from the Triassic Sherwood Sandstone Group are commonplace for "large diameter" boreholes and some have yields in excess of 8640 m^3 d^{-1}. Groundwater abstraction from the Sherwood Sandstone Group in the northern part of the basin peaked in 1960 at 93,312 m^3 d^{-1} but has since declined to 19,872 m^3 d^{-1} in 1982 (Plant et al., 1999). Some ingress of saline water (and contamination of potable supplies by saline water) has occurred beneath the large conurbations of Merseyside due to historic over-abstraction. Over-abstraction was due to heavy water use by industrial processes and although industrial use of groundwater has declined due to a combination of changes in the nature of industrial operations, industrial decline and improved plant efficiency, once an aquifer becomes contaminated (in this case by saline water) it is difficult to reverse. In deeper parts of the basin groundwater naturally becomes increasingly saline which has implications on well infrastructure design for geothermal use; potential problems with scaling and corrosion may be encountered but can easily be managed. The underlying Permian Collyhurst sandstone is of continental aeolian origin, this formation is 557 m thick in the Knutsford-1 borehole [SJ77NW4] and 515 m thick in the Prees-1 Borehole [SJ53SE3] in the southwest of the basin (Evans et al., 1993). The Permian Collyhurst Sandstone has supported yields of 1728 to 2592 m^3 d^{-1} from "large diameter" boreholes (Plant et al., 1999).

The Cheshire Basin has also been of interest for hydrocarbon exploration since the late 1970s (Mikkelsen and Floodpage, 1997), though as yet few wells have been drilled. Oil seeps are more commonly found around the periphery of the basin within Carboniferous strata (Mikkelsen and Floodpage, 1997). However, discoveries within the basin have been reported. Figure 6-9 indicates the hydrocarbon shows and discoveries that have been made across the Cheshire Basin to date. Whilst not over-run with discoveries, Mikkelsen and Floodpage (1997) concede that ignoring the hydrocarbon potential of the basin is unwise given the sparse dataset available for the area.

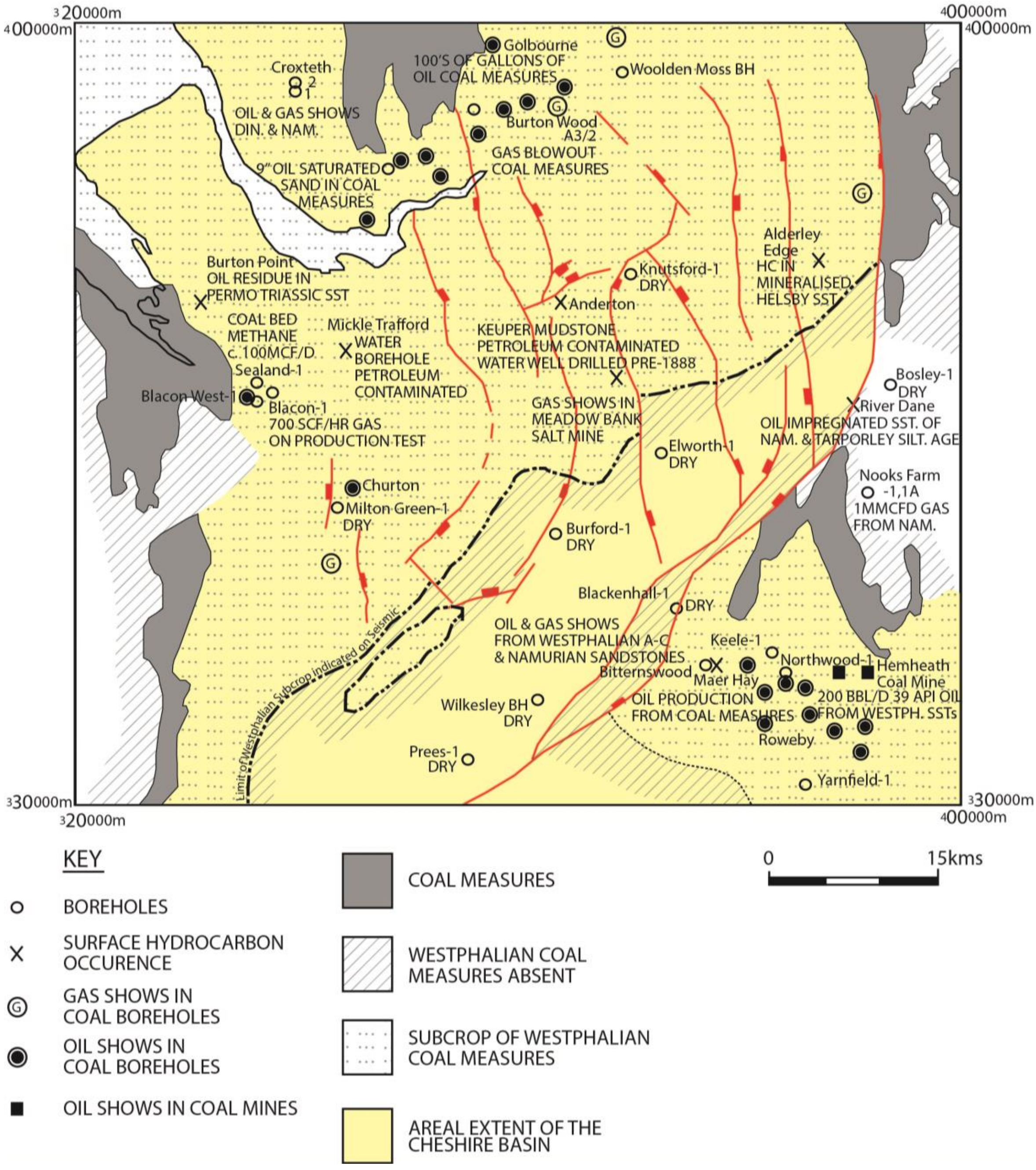


Figure 6-9: Location of hydrocarbon occurrences within the Cheshire Basin. In addition it shows where possible Westphalian subcrop exists (Mikkelsen and Floodpage, 1997).

6.5.2 Wells, temperature measurements and thermal gradient: Cheshire Basin

Borehole data for the basin are limited with only the Prees-1 and Knutsford-1 boreholes having proven the entire succession of the basin fill or penetrated the basin floor in the central part of the Cheshire Basin (Table 6-2). Both Banks-1 and Little Crosby wells lie outwith the main basin (Figure 6-7). Uncorrected temperature data from six boreholes (Plant et al., 1999) over a range of depths in metres below ground level (mBGL) are shown in Table 6-2 and Figure 6-10. Figure 6-10 indicates that temperatures of 40ºC will be reached within the Cheshire Basin at depths of around 1.5 km. Figure 6-11 shows a line of best fit through the data indicating a temperature gradient of 21°C km^{-1} exists based on the data presented (assuming a surface temperature of 10°C). In the deepest parts of the Cheshire Basin where the base of the Permian sandstone lies at depths of around 4.5 km, temperatures approaching 100ºC could be expected (Figure 6-10, Figure 6-12).

Table 6-2: Depth and Temperature data for boreholes in the Cheshire Basin (Plant et al., 1999).

Prees SJ53SE3		Burford SJ65SW13		Elworth SJ65SW53		Knutsford SJ77NW4		Banks-1 SD382210		Little Crosby SD325012	
Temperature °C	Depth mbgl	Temperature °C	Depth mbgl	Temperature °C	Depth mbgl	Temperature °C	Depth mbgl	Temperature °C	Depth mbgl	Temperature °C	Depth mbgl
53	1731	26	668	36	1089	27	715	37.2	742	29.4	748
56	1932	28	751	39	1318	31	909	52.2	2148	28.3	1140
59	2164	30	837			39	1500	52.2	2122	28.9	750
62	2396					43	1803	36.7	743		
66	2750					45	2000	52.2	2169		
70	2889					51	2230				

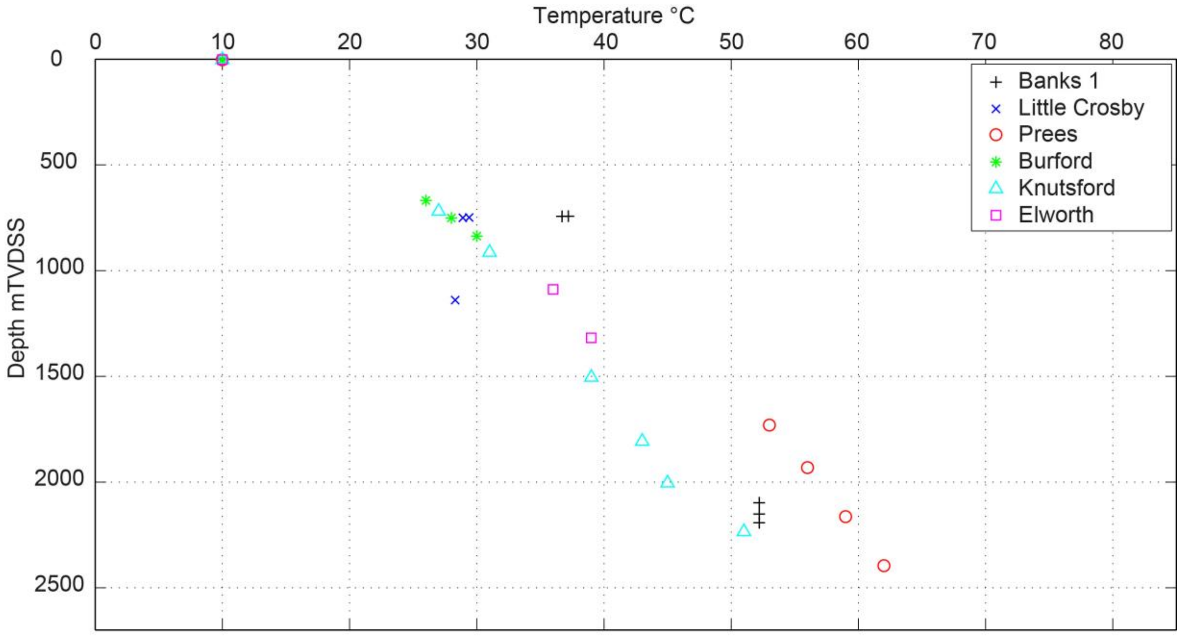


Figure 6-10: Depth temperature profiles in the Cheshire Basin.

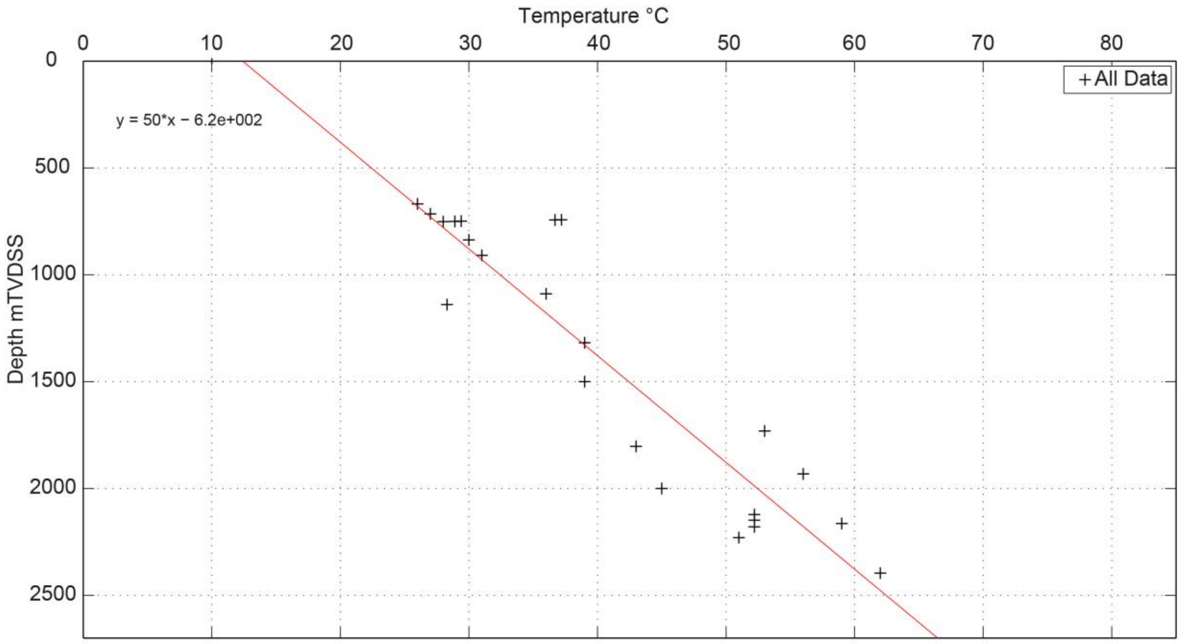


Figure 6-11: Depth temperature profiles in the Cheshire Basin. These temperatures are based on uncorrected temperature data.

The dataset for Cheshire has since been corrected but these values are not published and are therefore unavailable for assessment. Busby (2014) indicates the corrected geothermal gradient across the basin is 27°C km^{-1}. Plant et al. (1999) discussed geothermal gradients within the basin, stating a value of 20°C km^{-1} is the average across the area, based on a basin-wide heat-flow of 30-50 mW m^{-2} which is below the UK average of 52 mW m^{-2} (Busby, 2010). Coal mines along the periphery of the basin in Lancashire indicate a gradient of 20-22°C km^{-1}. North Staffordshire Coalfield geothermal gradients are higher (37°C km^{-1}).

Temperature has been modelled by Busby (2011) across the Cheshire Basin, presented in Figure 6-12. These data are modelled on the base of the Collyhurst Sandstone (base-Permian) and show an increase towards the basin depocentre where individual Formation thickness is likely to be greatest.

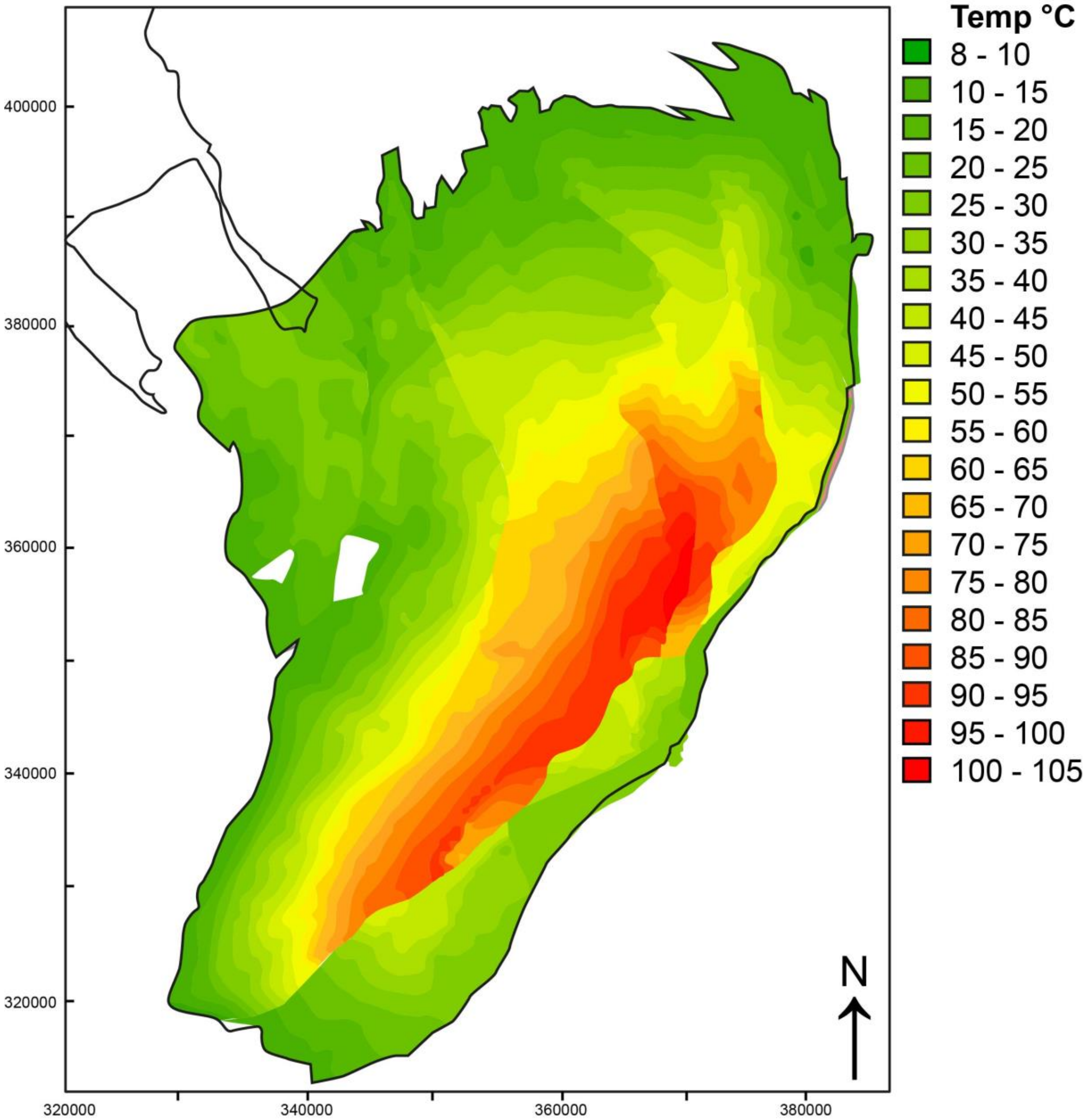


Figure 6-12: Modelled temperature at the base of the Collyhurst Sandstone (Busby, 2011).

6.5.3 Basin Overview: The East Irish Sea Basin

The Cheshire Basin is contiguous with the offshore East Irish Sea Basin (EISB); it is linked by a narrow neck comprising the Wirral Peninsula and coastal areas of Merseyside (Figure 6-5). Figure 6-13 shows the generalised geology of the Irish Sea area, along with the location of hydrocarbon fields and wells within the basin. The Cheshire Basin and EISB show a connectivity and similarity with regards the identified productive strata. Both the Cheshire Basin and EISB target the Triassic Sherwood Sandstone, a horizon that is important in both basins for hydrology and hydrocarbons respectively. The Collyhurst Sandstone has also been targeted, though lacks a seal within some areas of the basin. The lack of seal, however, is less important when considered as a geothermal target.

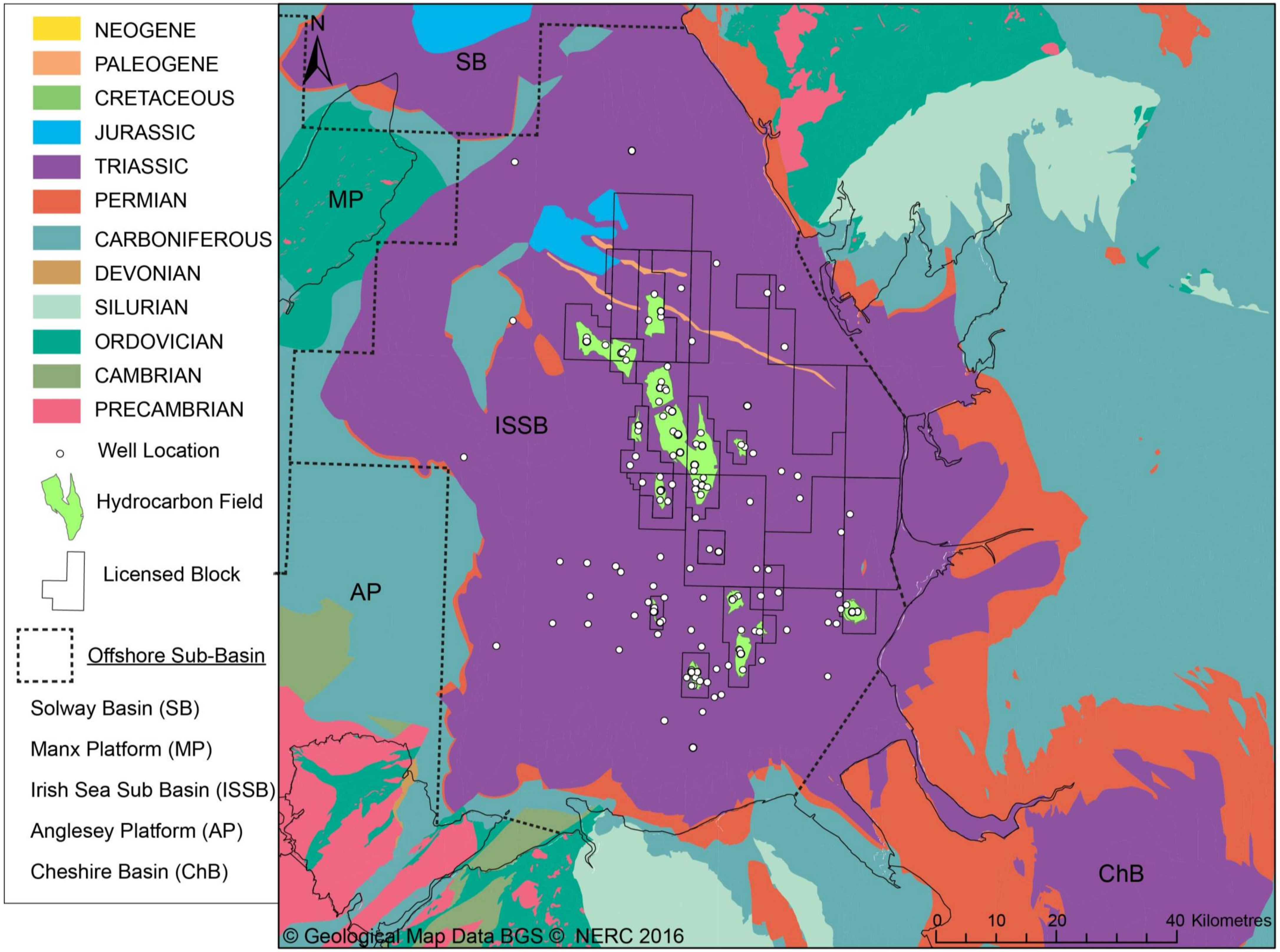


Figure 6-13: Generalised geology of the East Irish Sea Basin and surrounding areas (DECC, 2016; Green et al., 1997).

The EISB has been well explored for hydrocarbons and has 14 producing gas and oil fields that range in size from several tens of billion cubic feet to trillion cubic feet (Gluyas and Hichens, 2003). Historic oil, gas and water production from 13 fields can be found in Figure 6-14 (DECC, 2016). All EISB fields produce from the Triassic Sherwood Sandstone interval, although at least one discovery has been made and tested in the deeper Permian Collyhurst sandstone in the northern part of the basin. Few wells have penetrated the Carboniferous, and although gas shows have been recorded nothing has been classified as a discovery at this stratigraphic level. The source of most of the gas in the basin is the Carboniferous Westphalian coals while some of the gas and all of the oil (in the southern EISB) come from the basal Namurian Holywell Shale (Armstrong et al., 1995; Newport, 2016). The value of the EISB as an analogy for the Cheshire Basin comes from the numbers of wells drilled and the reservoir information collected. The extensively explored and exploited Triassic Sherwood Sandstone is for the most part high quality reservoir (Table 6-3). However in the north of the area some degradation of reservoir quality is apparent with pore-bridging and pore-filling illite cement in the sandstones of North Morecambe and Millom. Cowan and Bradney (1997) interpreted the illite cement as the product of local mineralising fluids. Localised cementation apart, measured flow rates in wells drilled elsewhere in the basin are substantial. The oilfield's peak production from Douglas was 8208 m^3 d^{-1} from 11 wells and for Lennox 6566 m^3 d^{-1} from seven wells of light, low viscosity oil (DECC, 2016). These flow rates are for oils with similar viscosity to water from wells of outside diameter only 9 $^5/_8$" (Yaliz and McKim, 2003).

Table 6-3: Reservoir properties for East Irish Sea oil and gas fields (compiled from data in Gluyas and Hichens (2003).

Field	Reservoir Interval	Net to Gross (fraction)	Average Porosity %	Average Permeability mD	Data Source
Douglas	Triassic Sherwood Sandstone	0.95	18	2000	Yaliz & McKim, 2003
Hamilton	Triassic Sherwood Sandstone	1	15	1300	Yaliz & Taylor, 2003
Hamilton North	Triassic Sherwood Sandstone	1	15	320	Yaliz & Taylor, 2003
Lennox	Triassic Sherwood Sandstone	0.95	15	approx. 1000	Yaliz & Chapman, 2003
North Morecambe	Triassic Sherwood Sandstone	0.92	10	100	Cowan & Boycott-Brown, 2003
North Morecambe	Triassic Sherwood Sandstone	0.92	11	0.5	Illite affected interval
South Morecambe	Triassic Sherwood Sandstone	0.79	14	150	Bastin et. al, 2003
Millom	Triassic Sherwood Sandstone	(not recorded)	9	0.5	Cowan & Bradney, 1997

Data for four fields within the EISB have been made available for review from ENI. These are the Hamilton, Douglas, Lennox and Conwy fields. An additional set of exploration wells have also been made available. These fields have been chosen given their close proximity to the onshore portion of the basin shown on Figure 6-15.

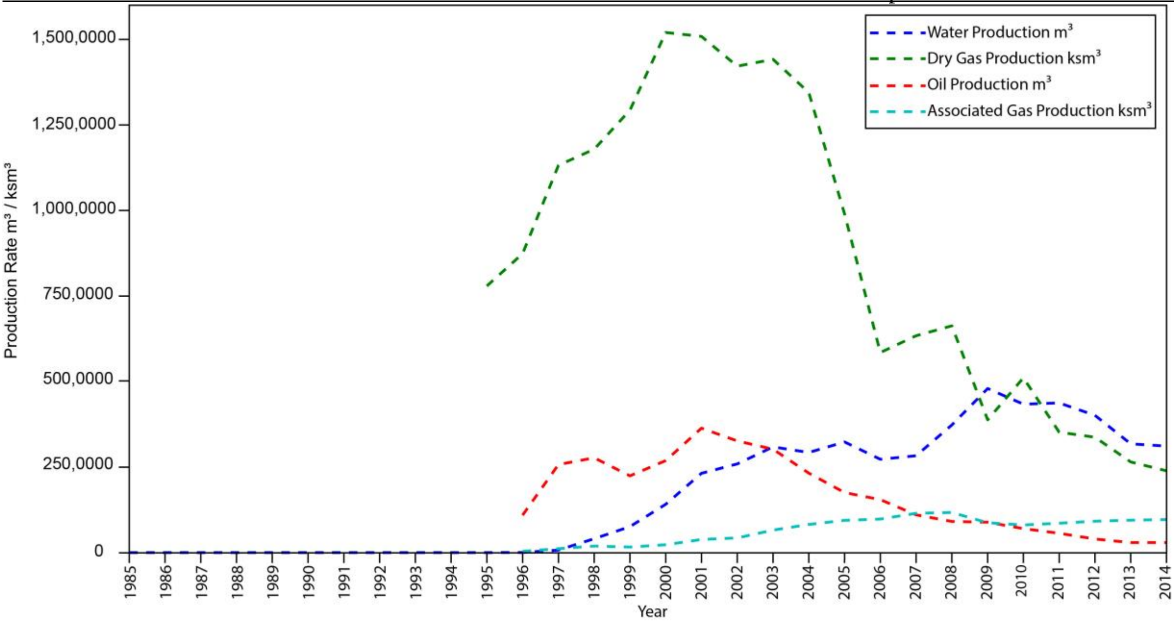


Figure 6-14: Oil, gas and water production from 13 fields within the East Irish Sea Basin (DECC, 2016).

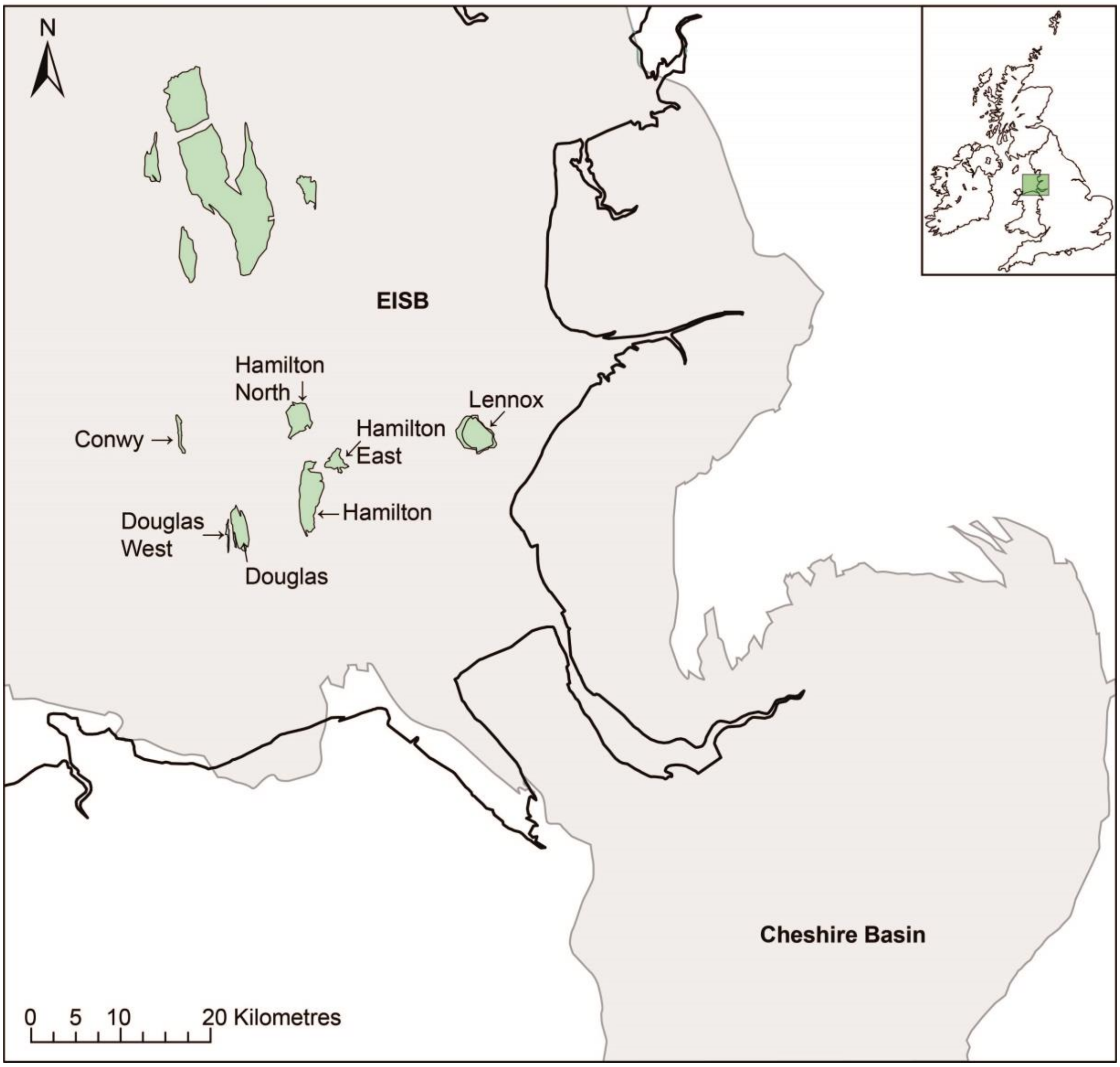


Figure 6-15: Location of the Hamilton, Lennox, Douglas and Conwy fields in relation to the Cheshire Basin (DECC, 2013b).

6.5.4 Wells, temperature and thermal gradient: East Irish Sea Basin

Temperature data for the EISB has been taken from well records for the Hamilton, Lennox, Douglas and Conway fields. Additional data has been sourced from other individual exploration wells and from the Liverpool Bay well and is displayed on Figure 6-16.

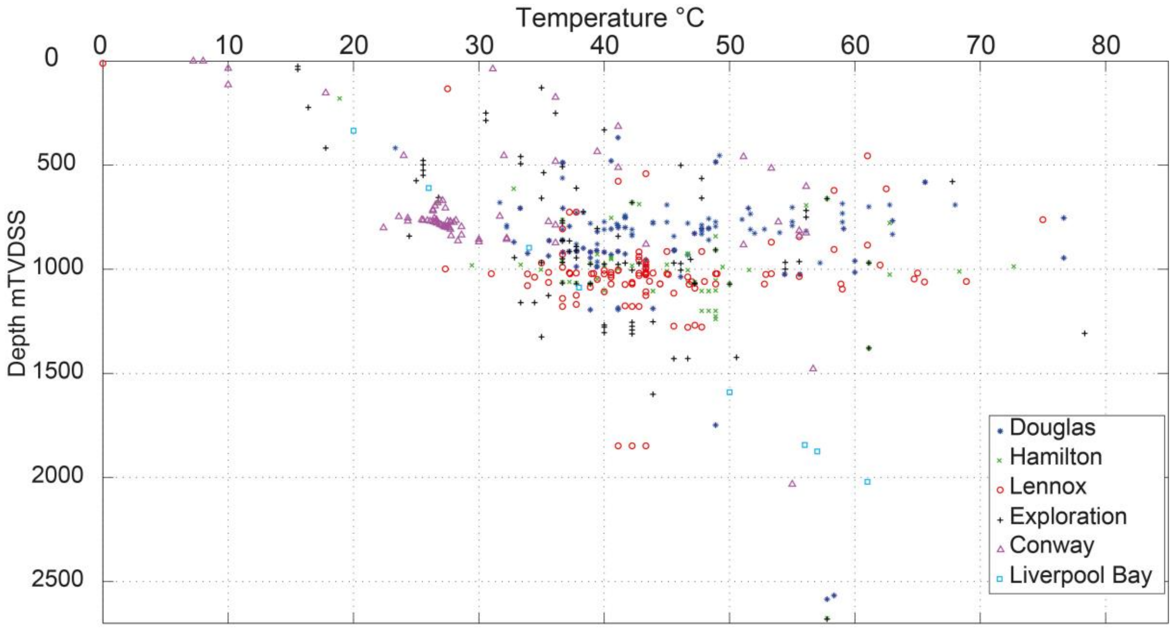


Figure 6-16: Temperature data for fields and exploration wells in the EISB.

A linear line of best fit for these data produces a temperature gradient of 32°C km^{-1}. The gradient has been calculated assuming a seabed temperature of 10°C.

Borehole temperatures taken from these wells are uncorrected and therefore are lower than true formation temperature. Temperature suppression is because during the drilling of a borehole, circulated drill fluid invades the surrounding formation causing temperatures to be suppressed. In addition, prior to any logging operations the well is circulated and flushed clean with water typically at a lower temperature than that of the surrounding formation (Bonté et al., 2012). Taking the raw temperature data for the EISB is likely to be suppressed by several °C, and therefore provides a conservative estimate of temperature at depth.

6.5.5 Reservoir/aquifer introduction and correlation

Both the Cheshire Basin and EISB extract fluid from the Sherwood Sandstone Group, and partially from the Collyhurst Sandstone (Figure 6-6). Within the Cheshire Basin aquifers and aquitards have been summarised by Evans et al. (1993) on Figure 6-17, with further division of the Helsby Sandstone noted in Figure 6-18. Within the Douglas, Hamilton and Lennox fields, the Ormskirk Sandstone (offshore equivalent of the Helsby Sandstone) forms the main reservoir unit which is split and correlated onshore as per Figure 6-18.

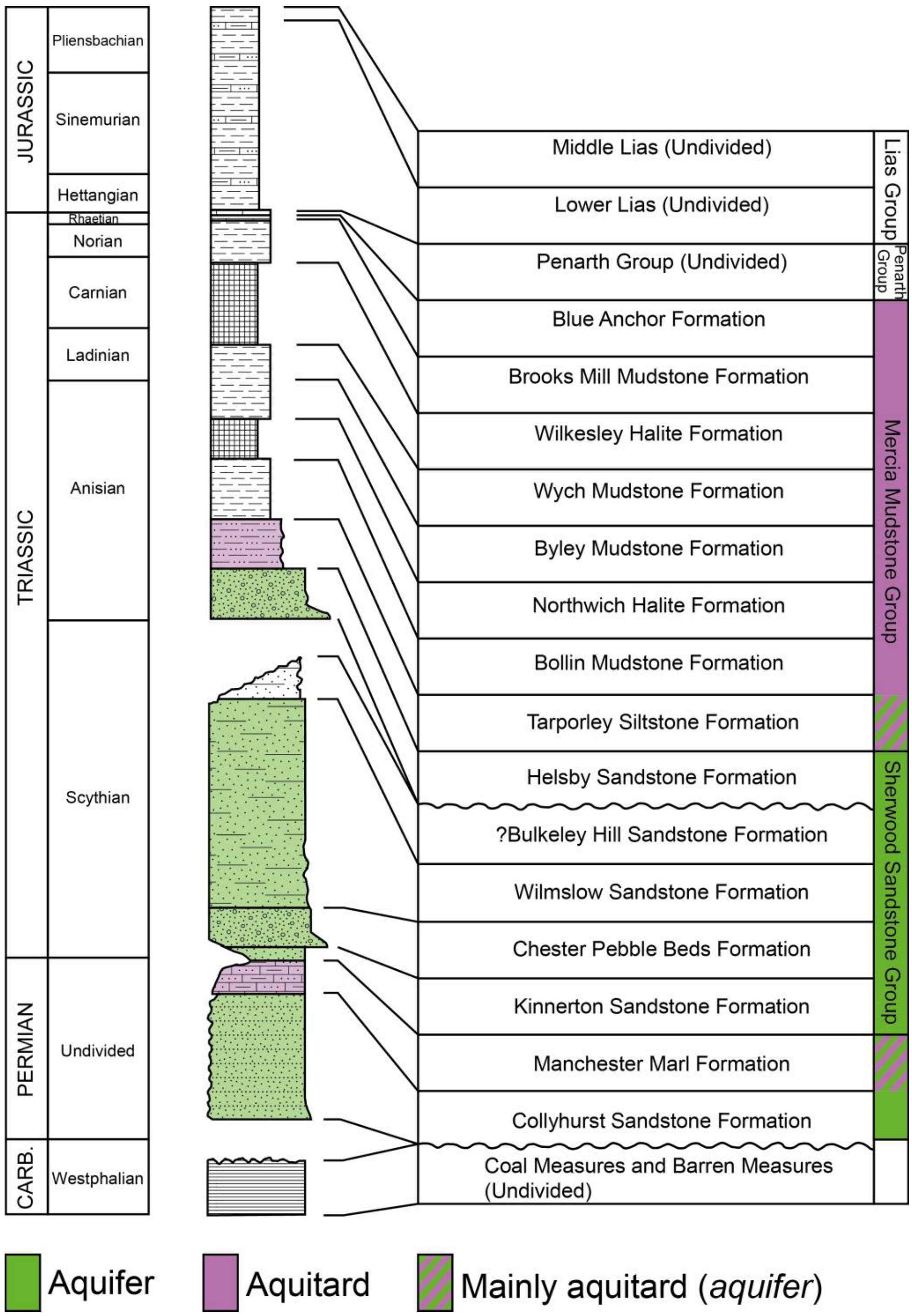


Figure 6-17: Aquifers and aquitards of the Cheshire Basin (Evans et al., 1993).

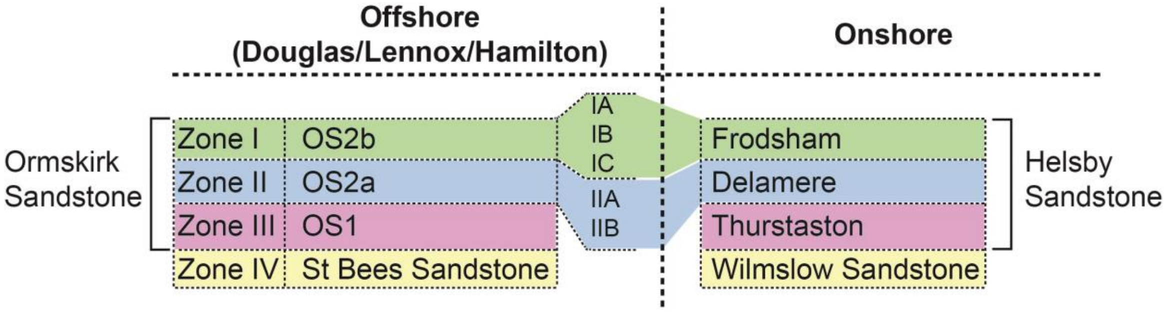


Figure 6-18: Correlation of the Ormskirk/Helsby Sandstone unit (Jackson et al., 1997; Plant et al., 1999; Yaliz and McKim, 2003; Yaliz and Taylor, 2003).

A general description of each unit is provided in Table 6-4. Detailed sedimentological descriptions of the reservoir units can be found in Plant et al. (1999) and British Geological Survey (1997). Further detail on the environment of deposition is discussed within Section 6.7.

Table 6-4: Summary reservoir description of the Collyhurst Sandstone and Sherwood Sandstone Group (British Geological Survey, 1997; Plant et al., 1999).

Unit	Description	Lithotype	Dominant depositional environment
Collyhurst Sandstone	Fine-medium grained, well sorted sand.	ND	Aeolian - fluvial
Kinnerton Sandstone	Fine-medium grained, moderately-well sorted, well rounded 'millet seed' grains (aeolian sands), poorly-moderately sorted, angular grains (interdune and fluvial sands).	Cherty sublithic arenites, quartz arenite	Aeolian - fluvial
Chester Pebble Beds	Medium-coarse grained, angular-subangular pebbly sandstone. Rare well rounded aeolian sand.	Quartz arenite, lithic arenite, sublithic arenite, arkoses, subarkoses, quartz wackes, lithic wackes,	Fluvial
Wilmslow Sandstone	Fine-medium grained, poor-moderately sorted (coarse zones display better sorting), angular-subrounded sands. Some reworked aeolian grains.	Cherty sublithic arenites, subarkoses (with minor proportions of lithic wackes, quartz wackes, litharenites, quartz arenites, lithic greywackes, silty mudstones and siltstones).	Fluvial
Helsby Sandstone	Coarse-fine grained, poorly sorted, angular-subangular fluvial sands, moderate-well sorted, 'millet seed' grained aeolian sands.	Quartz arenite, subordinate quartz and cherty sublitharenite, subarkosic sandstones	Frodsham (Zone I, OS2b)- aeolian Delamere (Zone II, OS2a- fluvial Thurstaston (Zone III, OS1) - aeolian
*ND denote No Data			

6.5.5.1 Aquifer Data Availability

The distribution of boreholes and water wells penetrating the onshore Cheshire Basin has been assessed in the first instance and are presented on Figure 6-19. Approximately 95% of all wells (boreholes and water wells) in the SJ Grid Square are either shallow (<50 m) or confidential and are of limited use. The data associated with these records is minimal (lithological logs only). The British Geological Survey (1997) have further published aquifer properties data for major and minor aquifers in England and Wales, the data (transmissivity, porosity and hydraulic conductivity/permeability) for which has been obtained from some of the boreholes and water wells identified on Figure 6-19. Within the BGS database there are some porosity, transmissivity and hydraulic conductivity data for the Cheshire Basin, the majority of which are from Permo-Triassic sandstones that can be of some use. Data specific to the Collyhurst Sandstone are not reported. The well locations for these data within the Cheshire Basin are presented on Figure 6-20. Values of depth for these wells have been obtained (where available) from the BGS GeoIndex. Where depth was noted as ‘unknown’, a value of zero (i.e. surface) has been assumed. The index of all wells can be found in Appendix F1. Deep well penetrations (wells >500 mBGL) are presented on Figure 6-7. Further to this database onshore aquifer properties data have been collated from Plant et al. (1999), Rollin et al. (1995) and Bloomfield et al. (2006).

Porosity and permeability data for the offshore Douglas, Hamilton and Lennox fields have been provided by ENI, along with additional exploration well data. Additional data from Yaliz and McKim (2003), Yaliz and Taylor (2003) and Yaliz and Chapman (2003) have also been used where necessary. A total of 94% of data primarily relate to the Helsby Sandstone reservoir zone as it forms the target hydrocarbon reservoir across the EISB, and as such forms the focus of testing. Within the Hamilton, Douglas and Lennox fields, a total of 73 wells have available data, of which only two penetrate the Collyhurst Sandstone (Douglas field wells 110/13-12 and 110/13b-21). A further 23 terminate in the Wilmslow Sandstone, the remainder penetrating the Helsby Sandstone only. The tested intervals are split as per Figure 6-18. Additional offshore porosity and permeability data for the Collyhurst Sandstone and Wilmslow Sandstone Formations have been extracted from 11 and eight exploration wells respectively. No offshore data was available for the Chester Pebble Beds Formation or Kinnerton Sandstone Formation.

Analyses of the data described above have been collated and are presented within Section 6.11.

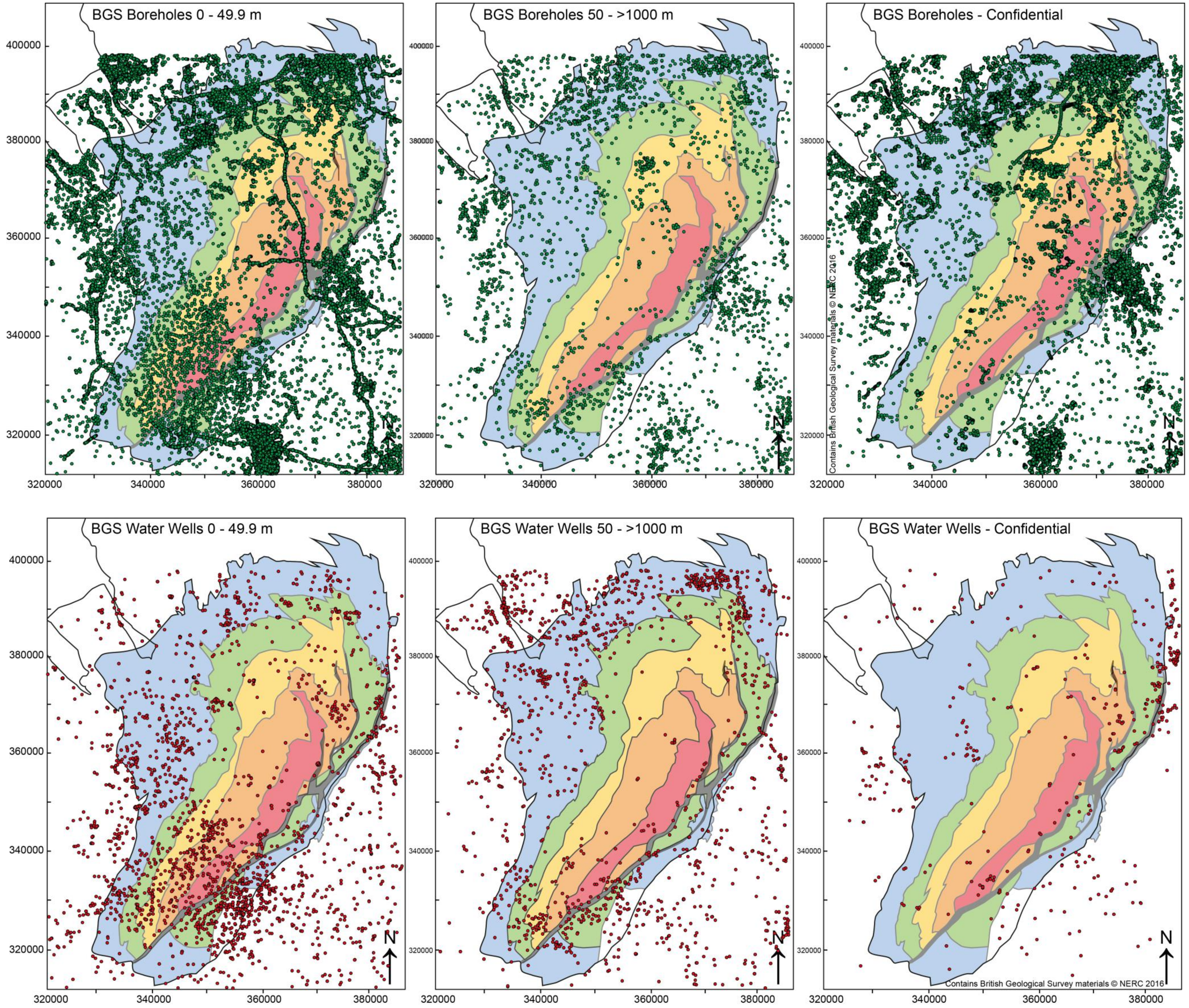


Figure 6-19: Boreholes and water wells located within the Cheshire Basin. For coloured polygon information refer to Figure 6-8 (Plant et al., 1999).

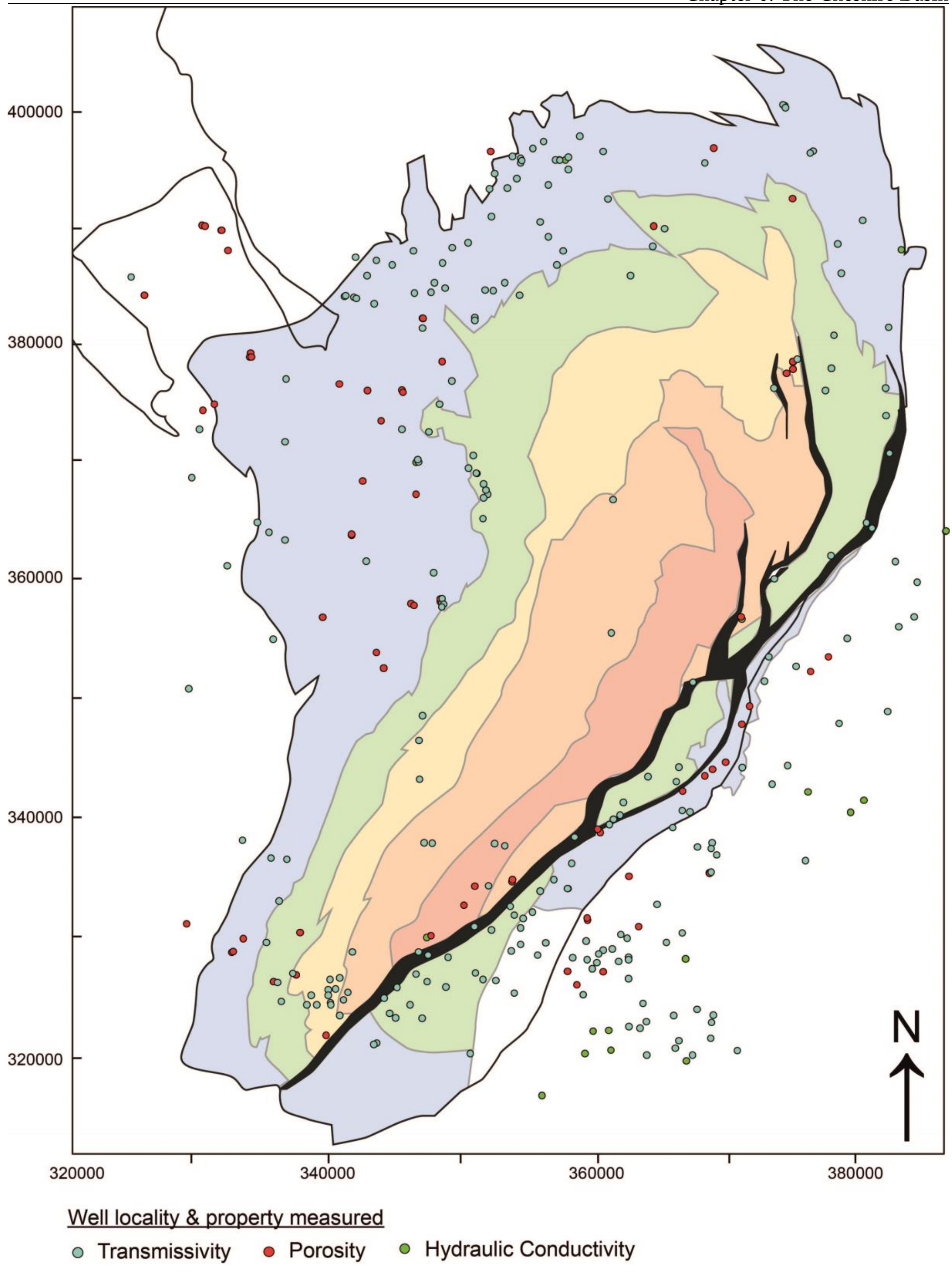


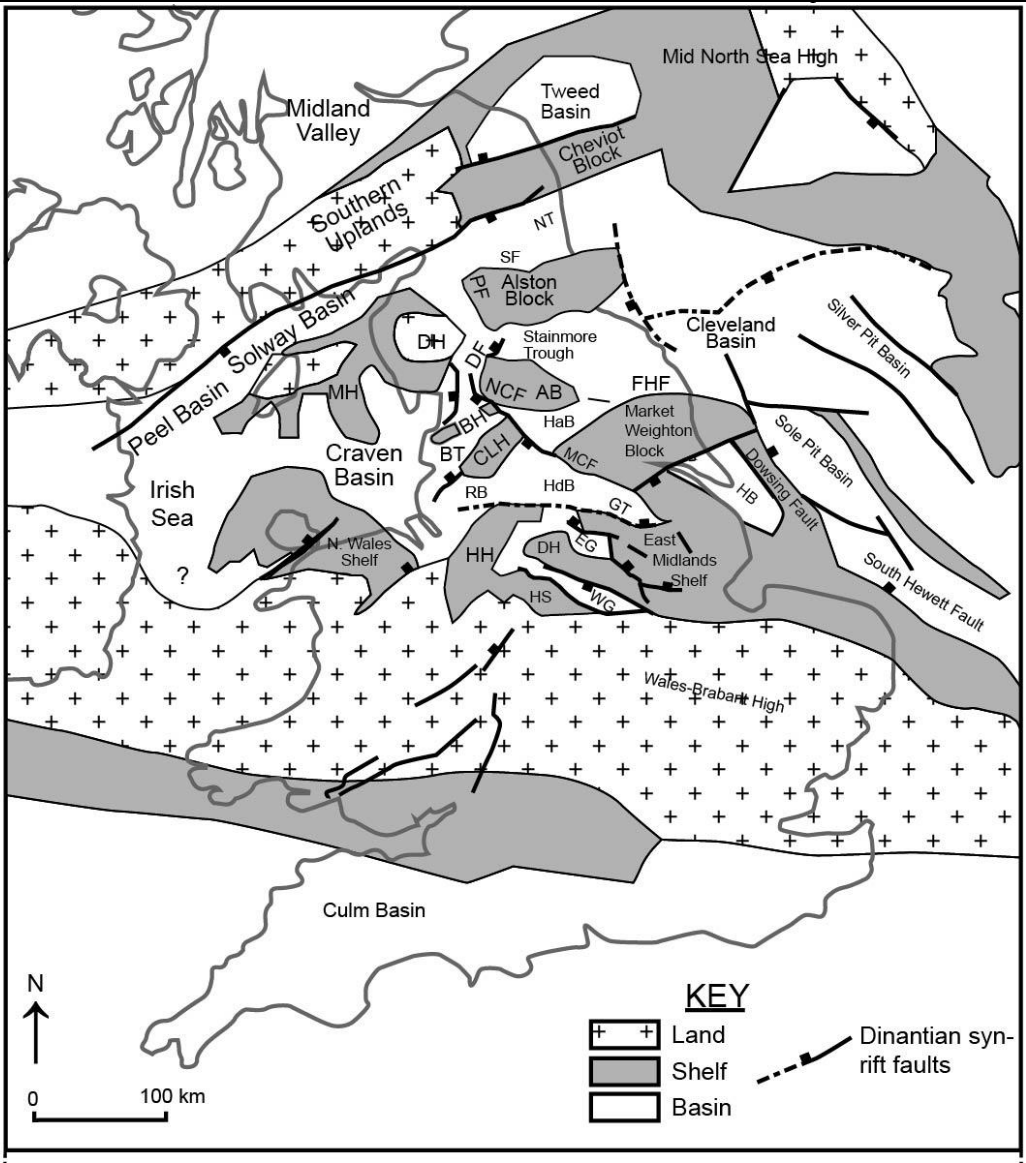
Figure 6-20: Location of wells containing transmissivity, porosity or hydraulic conductivity data for the Cheshire Basin (British Geological Survey, 1997). Refer to Figure 6-8 for coloured polygon background (Plant et al., 1999).

6.6 Basin Comparison: Depositional Environment

6.6.1 Pre-Permian Paleogeography, Tectonics & Sedimentation

Underlying and surrounding the main Permo-Triassic basin fill of the Cheshire Basin and EISB are Palaeozoic rocks of predominantly Carboniferous age (Plant et al., 1999). The nature of the stratigraphy and structure over which the main Permo-Triassic basin occupies is described briefly here. Of ultimate importance is the structural control these successions exert on the overlying younger basin fill.

The Caledonian Orogeny (late Cambrian – mid Devonian) is largely responsible for creating the structural grain of Britain. Later extension and inversion events during the Devonian and Carboniferous have been focused along the structural fabric already engrained within older basement rocks (TOTAL E&P UK, 2007) due to the earlier Caledonian event. North-south extension during early Carboniferous times caused a series of horst and grabens/half grabens to develop, indicated on Figure 6-21. Britain was located in equatorial latitudes at this time and deposition was dominated by carbonate-rich sediment, including the formation of thick limestone sequences across elevated platform areas and mixed carbonate and clastic turbidite and other deep water sequences in the basinal areas. The N-S extension seen throughout the Dinantian began to subside at the onset of the Namurian and thermal relaxation controlled basin subsidence during the later Namurian and Westphalian. Major delta systems originating from the northwest developed in a humid climate throughout the Namurian and Westphalian, further burying the Dinantian rift topography (Figure 6-22).



AB - Askrigg Block; **BH** - Bowland High; **BT** - Bowland Trough; **CLH** - Central Lancashire High; **DF** - Dent Fault; **DH** - Derbyshire High; **EG** - Edale Gulf; **FHF** - Flamborough Head Fault; **GT** - Gainsborough Trough; **HaB** - Harrogate Basin; **HdB** - Huddersfield Basin; **HB** - Humber Basin; **HH** - Holme High and Heywood High; **HS** - Hathern Shelf; **LDH** - Lake District High; **MCF** - Morley-Campsall Fault; **MH** - Manx High; **NCF** - North Craven Fault; **NT** - Northumberland Trough; **PF** - Pennine Fault; **RB** - Rossendale Basin; **SF** - Stublick Fault; **WG** -

Figure 6-21: Dinantian paleogeography (Waters and Davies, 2006).

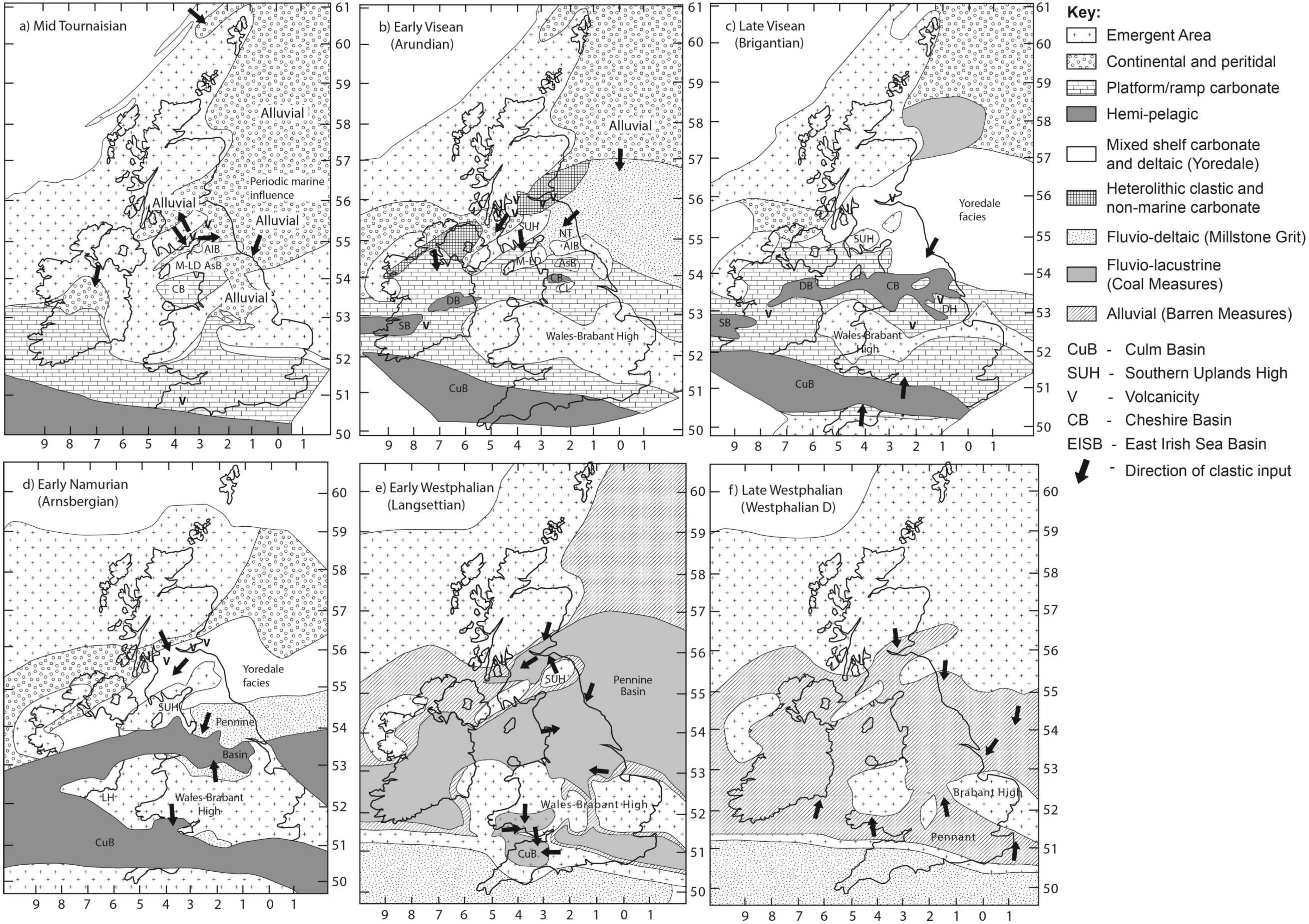


Figure 6-22: Further breakdown of Carboniferous paleogeography reconstructions indicating the depositional environments that dominated over the EISB and Cheshire Basin (Waters and Davies, 2006).

6.6.2 Permo-Triassic Overview

6.6.2.1 Permian

The conclusion of the Variscan Orogeny is marked by the formation of supercontinent Pangea. Britain still lay in an equatorial position but following continental collision it was now within the interior of Pangea. Desert conditions prevailed during the lower Permian with erosional products accumulating in dunes, ephemeral fluvial systems and sabkhas (Plant et al., 1999). It is likely NW-SE and NE-SW Caledonian basement structures were reactivated in response to E-W extensional tectonics (likely rifting in the North Atlantic) causing the formation of the Cheshire Basin, EISB and Stafford Basin (Figure 6-1, Figure 6-22). All these basins were dominated by aeolian-fluvial environments. The basal aeolian-fluvial Permian Collyhurst Sandstone was deposited on an irregular eroded Carboniferous surface across both the Cheshire Basin and EISB (Jackson and Mulholland, 1993). A major northward flowing fluvial system brought sediment to parts of the basin from the eroding Variscan massifs located to the south. Later in the Permian a marine incursion centred on the EISB led to the formation of the Manchester Marl (in the NW of the Cheshire Basin and offshore EISB) and the Bold Formation (in the southern part of the Cheshire Basin) and the St Bees Evaporite (EIS basin centre only – Jackson et al., 1997). The Manchester Marl is a dolomitic/gypsiferous mudstone whilst the Bold Formation (further from the depocentres) becomes progressively more arenaceous and silty (Plant et al., 1999). The St Bees Evaporite Formation is comprised of halite. Retreat of the St Bees Evaporite marine incursion marks the end of the Permian and a move into the Triassic. The marine influence lasted longer within the EISB.

6.6.2.2 Triassic

At the onset of the Triassic, the UK landmass had drifted to latitudes of 15-20°N and further rifting caused continued basin formation throughout the Triassic (Plant et al., 1999). The marine influence of the late Permian receded within the Cheshire Basin and a return to continental deposition occurred; a high energy braided river system developed within intervening areas dominated by aeolian deposition (Cowan, 1993). Ambrose et al. (2014) state the early Triassic was dominated by a large fluvial system originating from the south flowing northwards in a NNW-SSE active rift (Jackson et al., 1997). The Sherwood Sandstone Group was deposited throughout these times, the base of which is marked by the Kinnerton Sandstone Formation. It is likely the Kinnerton Sandstone Formation is of latest Permian age, but has been incorporated into the

Sherwood Sandstone Formation in early classifications and has remained so since (Ambrose et al., 2014). The Kinnerton Sandstone was deposited in an aeolian dune system with evidence of fluvial reworking in the vicinity (Plant et al., 1999). The lateral equivalent within the EISB is the Rottington Formation; a fluvial-origin sandstone. The Chester Pebble Beds overlie the Kinnerton Sandstone Formation, deposited as conglomerates and sandstones derived from the northward flowing river. The abundance of pebbles within Chester Pebble Beds decreases as you move northwards across the Cheshire Basin and as a consequence the unit is not homogenous laterally. These beds reach the south eastern margin of the EISB, but grade into a fluvially dominated sandstone (the Rottington Sandstone Member) from this point (Jackson et al., 1997). The Wilmslow Sandstone of the Cheshire Basin overlying the Chester Pebble Beds is similar and equivalent to the St Bees Sandstone Formation that likely formed in a NNW-trending fluvial system. Aeolian dune sandstones are also found within the St Bees Sandstone formed with an easterly prevailing wind. The Bulkeley Sandstone Formation lies conformably on top the Wilmslow Sandstone Formation, and is thought to be a continuation of the same depositional conditions. As such it is described as part of the Wilmslow Sandstone in this Chapter. The Hardegson disconformity separates the Wilmslow Sandstone Formation and the Helsby Sandstone Formation, which forms the uppermost unit of the Sherwood Sandstone Group. The disconformity is marked by a faulted and eroded surface that affects the majority of the basin (Plant et al., 1999). The Helsby Sandstone is a mixed aeolian-fluvial deposit and is laterally equivalent to the Ormskirk Sandstone Formation in the EISB. The depositional environment here is broadly similar to that seen within the Cheshire Basin. Paleocurrents in the Ormskirk Sandstone indicate an easterly supply of sediment was now entering the EISB, whilst within the Cheshire Basin the paleocurrents still suggest a large input from the southeast was dominant (Jackson et al., 1997; Plant et al., 1999).

The Upper Triassic section in both basins is occupied by the Mercia Mudstone Group; a thick alternating silty mudstone-halite succession. The Mercia Mudstone Group indicates a move away from arenaceous dominated environs and a move into more argillaceous playa and intertidal environments. The succession of dolomitic mudstones (Bollin, Byley, Wych and Brooks Mill) and halite (Northwich Halite, Wilkesley Halite) showed partial connectivity to a sea located over the EISB. Lateral heterogeneity was widespread with areas of desert environment, shallow short lived lakes and longer lived seas allowing the deposition of thick halite deposits. That said, correlation of the thicker halite and mudstone units between the basins is possible (Jackson et al., 1997; Wilson, 1990, 1993). Within the

Cheshire Basin the lower part of the Mercia Mudstone Group becomes increasingly arenaceous and is named the Tarporley Siltstone Formation. The Tarporley Siltstone is absent within the EISB (Mikkelsen and Floodpage, 1997).

6.6.2.3 Jurassic

Very little Jurassic strata remain within the Cheshire Basin or within the EISB, existing only as discrete outliers. The Lias Group (interbedded marine limestones and mudstones) overlie the Triassic. Plant et al. (1999) state that ascertaining the evolution beyond the Lias point is difficult given the lack of preserved strata. However, they do state from the data that are available that it is likely further basin subsidence occurred episodically in the Jurassic and Cretaceous. Subsidence is further discussed within the burial history (Section 6.8).

6.6.2.4 Facies heterogeneity

The depositional environment assigned to facies across both basins (fluvial vs aeolian) quoted in Table 6-4 should be treated with caution. Whilst it describes the dominant environment of deposition during that time it is known that fluvial and aeolian environments co-existed, as detailed in the previous sections. The area was actively changing over short timescales due to a changing water table and active fault growth (Edwards and Williams, 1993). There is evidence of lateral heterogeneity on a local and regional scale, with poor quality (mudstone/siltstone) reservoir facies forming potential vertical permeability barriers. Their persistence has been assessed by the British Geological Survey (2003) and Edwards and Williams (1993), who indicate they are in general thin (<1 m) and not laterally pervasive. Onshore the majority of these units persist for between 10-100 m before being cut out. They make up <10% of the reservoir sections. Within the Helsby Sandstone, 5% or less of this unit is comprised of non-reservoir (mudstone). Onshore the value is 5-10%. Cowan (1993) further states fluvial facies associations account for up to 90% of the upper Sherwood Sandstone Group (Helsby Sandstone and Wilmslow Sandstone), based on data from the Morecambe Field.

6.6.2.5 Formation thickness variation

Summaries of formation thickness variations are presented in Table 6-5 and 6-6. Increasing thickness of these formations is seen within the Prees-1 borehole onshore likely caused by being closer towards the main depocentre of the basin. Offshore thickness variation occurs but appears to be of similar magnitude within each field reflecting the lack of central depocentre, marking an inherent difference between the two basins.

Table 6-5: Onshore thickness data from [a] - British Geological Survey (2003), [b] - Downing and Gray (1986), [c] - Plant et al. (1999), [d] - Bloomfield et al. (2006), [e] - British Geological Survey (1997).

Formation (Location)		Thickness (m)
Helsby Sandstone	Helsby Sandstone (Lower Mersey Basin)[a]	>181-295
	Helsby Sandstone (North Mersey Basin)[a]	100-120
	Helsby Sandstone (Knutsford-1)[b]	419
	Helsby Sandstone (Prees-1)[b]	432
	Helsby Sandstone (Formby 1)[b]	296
	Helsby Sandstone[c]	100-250
	Helsby Sandstone[d]	230
	Helsby Sandstone (south basin)[e]	20-200
Wilmslow Sandstone	Wilmslow Sandstone (Lower Mersey Basin)[a]	>205-480
	Wilmslow Sandstone (North Mersey Basin)[a]	280
	Wilmslow Sandstone (Knutsford-1)[b]	595
	Wilmslow Sandstone (Prees 1)[b]	422
	Wilmslow Sandstone (Formby 1)[b]	203
	Wilmslow Sandstone[c]	280
	Wilmslow Sandstone (south basin)[e]	200-425
Chester Pebble Beds	Chester Pebble Beds (Lower Mersey Basin)[a]	>316-375
	Chester Pebble Beds (North Mersey Basin)[a]	145-420
	Chester Pebble Beds (Knutsford-1)[b]	490
	Chester Pebble Beds (Formby 1)[b]	376
	Chester Pebble Beds[c]	225-375
	Chester Pebble Beds (south basin)[e]	90-300
Kinnerton Sandstone	Kinnerton Sandstone (Lower Mersey Basin)[a]	0->80
	Kinnerton Sandstone (North Mersey Basin)[a]	10-80
	Kinnerton Sandstone (Knutsford-1)[b]	75
	Kinnerton Sandstone (Formby 1)[b]	37
	Kinnerton Sandstone (south basin)[e]	0-300
Collyhurst Sandstone	Collyhurst Sandstone (Lower Mersey Basin)[a]	283-720
	Collyhurst Sandstone (North Mersey Basin)[a]	0-300
	Collyhurst Sandstone (Knutsford-1)[b]	555
	Collyhurst Sandstone (Formby 1)[b]	715

Table 6-6: Summarised reservoir thickness of Permo-Triassic sandstones within study area (courtesy of ENI).

Formation	Thickness (mTVDSS)		
	Douglas	Hamilton	Lennox
Helsby Sandstone	91-249+	135-225	68-273
Wilmslow Sandstone	367-679	34-276+	648
Chester Pebble Beds	421	-	-
Kinnerton Sandstone	25-55	-	-
Collyhurst Sandstone	42-834+	704	-

6.7 Basin Evolution: Burial History

Deposition of Permo-Triassic sediments occurred during rifting and subsidence of each basin. It is clear that from the current nature and distribution of sediment within both basins they are not currently at their maximum depth; an amount of exhumation has occurred (Plant et al., 1999). The timing and magnitude of these burial and exhumation phases is an important consideration when assessing the EISB as an analogue for the Cheshire Basin, and also in understanding the larger scale processes that occurred in the region throughout the development of the basins. The development of diagenetic phases, hydrocarbon maturation and the structures that formed during and after burial and exhumation will all affect the target reservoir quality.

The economic viability of a geothermal resource can be increased if additional high energy hydrocarbon streams can be co-produced. The Cheshire Basin has been previously considered for hydrocarbon exploration but has not yet proven any resources despite the neighbouring EISB being a prolific producer since the 1970’s (Colter, 1997). Section 6.7 will also, therefore, assess the maturation history and provide a view on the likelihood that hydrocarbons exist within the Cheshire Basin.

6.7.1 Burial and maturation history

The assessment of burial history within the Cheshire Basin is based on limited data. Evans et al. (1993) presents a burial history up to end-Jurassic, whilst Plant et al. (1999) cover the full age range (to present). Burial history studies for the offshore EISB are more numerous due to their being a requirement for understanding the hydrocarbon maturation history for the area. Data from Holford et al. (2005), Floodpage et al. (2001), Haig et al. (1997) and Hardman et al. (1993) have been used in this case. Figure 6-23 shows a broad overview of the key burial/exhumation/hydrocarbon generation timescales for both the Cheshire Basin and EISB based on Green et al. (1997), Holford et al. (2005), Hardman et al. (1993), Floodpage et al. (2001), Plant et al. (1999), Haig et al. (1997), Mikkelsen and Floodpage (1997) and Edwards and Williams (1993).

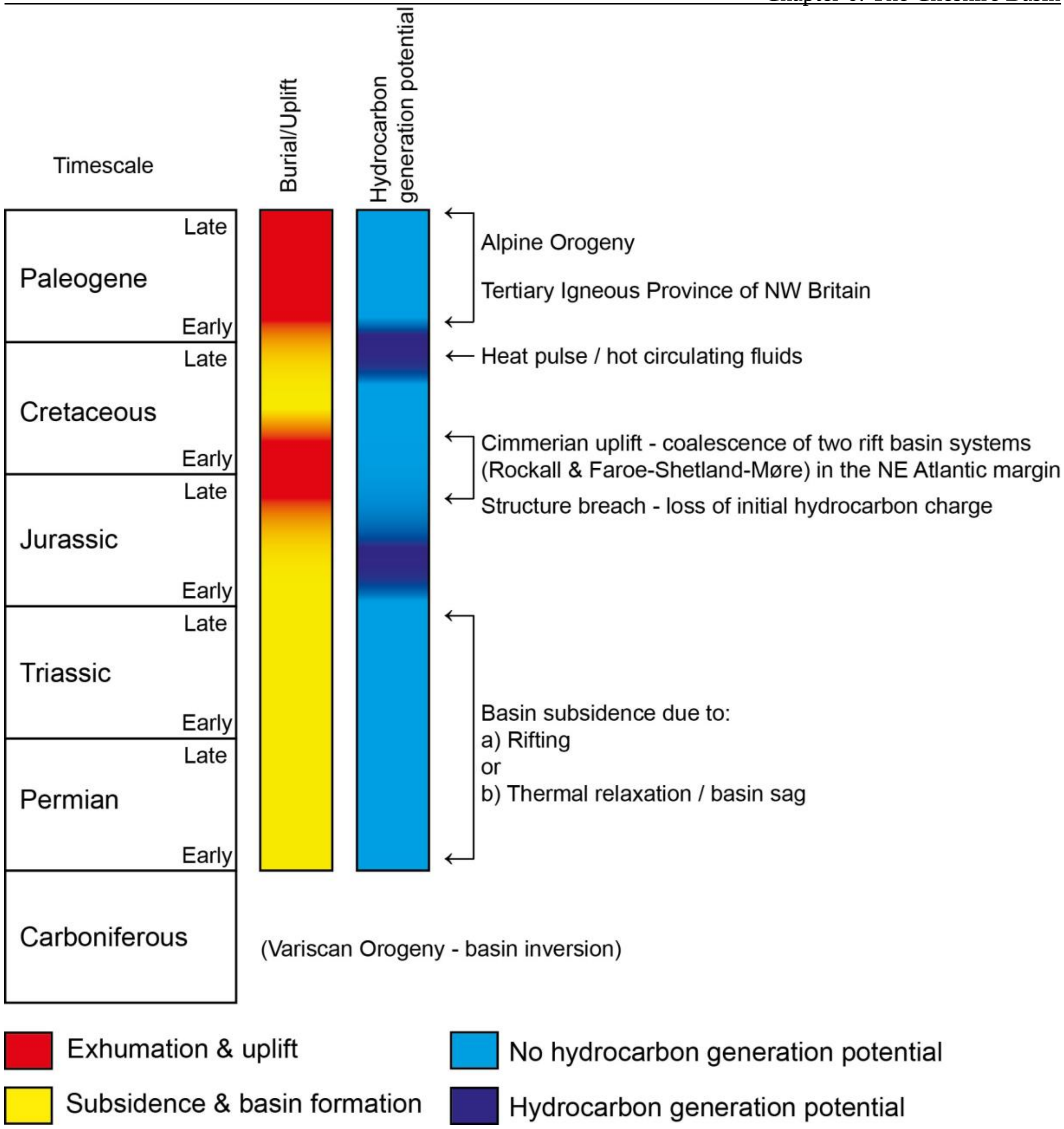


Figure 6-23: Burial and exhumation history summary for the Cheshire Basin and EISB based on the work of Green et al. (1997), Holford et al. (2005), Hardman et al. (1993), Floodpage et al. (2001), Plant et al. (1999), Haig et al. (1997), Mikkelsen and Floodpage (1997) and Edwards and Williams (1993).

The timing of each event varies by author but is broadly synonymous. The key difference between the two basins is the **magnitude** of the burial and exhumation events. Apatite Fission Track Analysis (AFTA) and Vitrinite Reflectance (VR) data for both basins has been used by several authors to assess the amount of burial and subsequent exhumation (Figure 6-24). A comparison of burial curves for wells across both basins has allowed an assessment of the maximum depth attained by the sediments, the maximum paleotemperature of these strata and subsequent loss of strata via exhumation with a view to determine the likely effect on reservoir quality (Table 6-7).

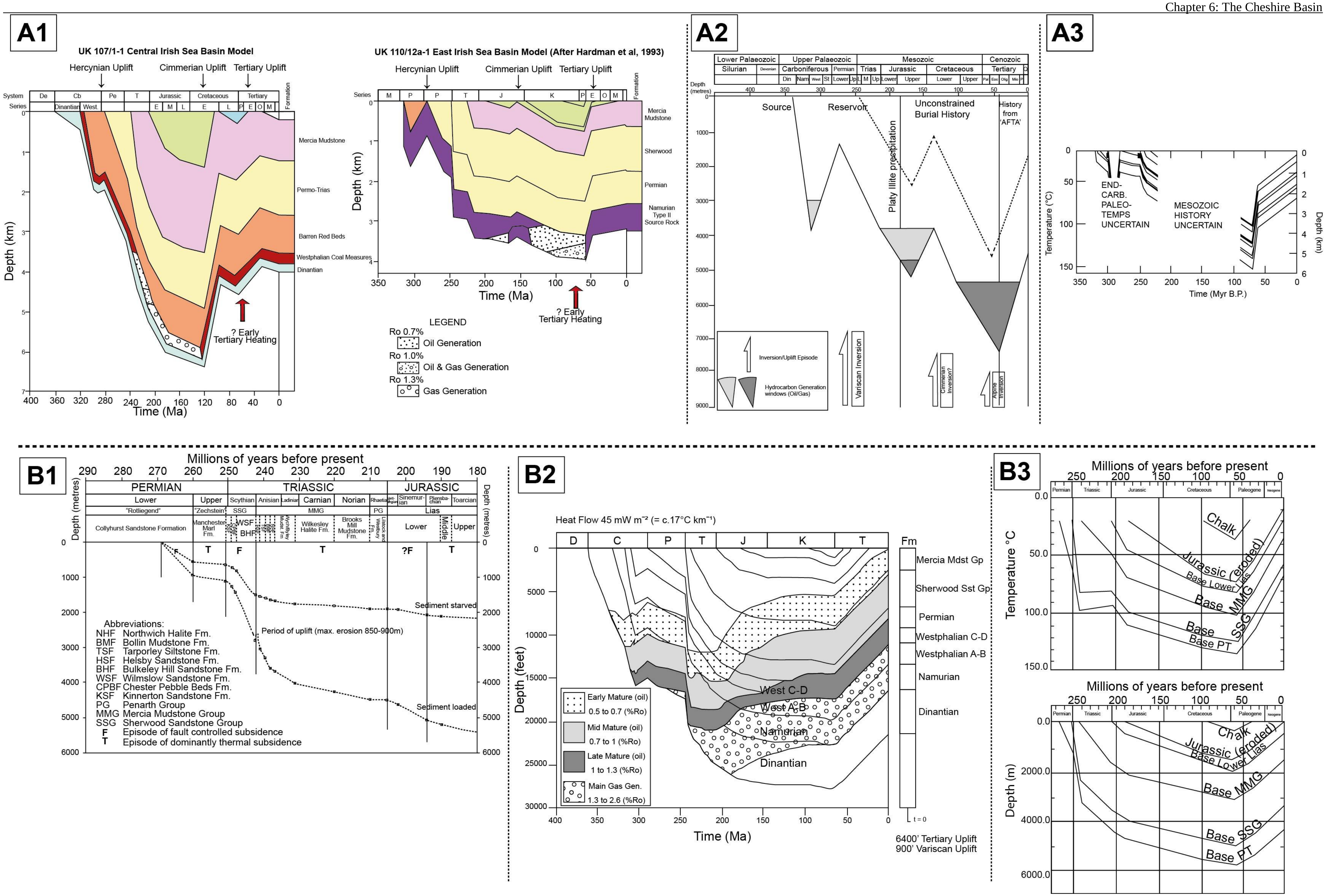


Figure 6-24: Reconstructed burial history for the EISB ('A') and Cheshire Basin ('B'). A1 – Floodpage et al. (2001) A2 - Cowan and Bradney (1997), A3 – ENI, B1 - Evans et al. (1993), B2 - Mikkelsen and Floodpage (1997), B3 – Plant et al. (1999).

Evidence of three exhumation phases has been identified across both basins, listed below. These exhumation phases can all be linked to major tectonic and structural events that occurred on a continent-scale.

- Late Jurassic – early Cretaceous (Cimmerian): attributed to the joining of two large Atlantic rift systems (Rockall to the south, Faroe-Shetland-Møre to the north) and the associated rotation of the principal horizontal stress regime linked to seafloor spreading (Holford et al., 2005).
- Early Paleogene: NW-directed compression as a result of the Alpine Orogeny and some possible uplift associated with the North Atlantic continental break-up.
- Late Paleogene – Neogene: Alpine Orogeny / opening of the North Atlantic.

The magnitude of each cooling and exhumation event across the EISB and Cheshire Basin has been difficult to constrain as the magnitude of each event has been purported to vary spatially. Within the EISB it has been suggested the main phase of cooling and exhumation occurred during the early Paleogene (Floodpage et al., 2001; Hardman et al., 1993). Holford et al. (2005) re-interpreted the data as showing the largest cooling and exhumation phase to have occurred in the Early Cretaceous instead, with successive exhumation phases being of a lesser magnitude. Within the Cheshire Basin, (Mikkelsen and Floodpage, 1997) present data showing VR data for the Knutsford-1 borehole from Westphalian 'C' coals are 1.18-1.32% indicating early gas maturity. The burial curve for Knutsford-1 (Figure 6-24) indicates the base of the Westphalian reached peak oil maturity in mid-Triassic times, gas generation began in early Jurassic and peak gas was reached in middle Jurassic. It was terminated by early Paleogene uplift. The Late Jurassic-Early Cretaceous (Cimmerian) exhumation phase is discussed by the author but the amount of uplift is not quantified; it is described as being a "moderate amount of erosion". Although the estimate is based on only one well, it is suggested Cimmerian uplift did not amount to much within the Cheshire Basin. Modelled burial and thermal histories by Plant et al. (1999) also support this theory.

Table 6-7 presents data from seven authors for estimates of exhumation across each basin. All apart from Holford et al. (2005) indicate broadly similar exhumation was experienced by both basins. Table 6-7, along with Figure 6-24 for each area, gives an appreciation of the depths these sediments have been subjected to. Cheshire Basin sediments are likely to have achieved a maximum burial depth of 6-8 km with paleotemperatures reaching 130-140°C.

Table 6-7: Exhumation across the Cheshire Basin and EISB (Colter and Ebbern, 1978; Edwards and Williams, 1993; Evans et al., 1993; Green et al., 1997; Holford et al., 2005; Mikkelsen and Floodpage, 1997; Plant et al., 1999).

<table>
<tr><th>Area</th><th>Author</th><th>Late Jurassic - early Cretaceous (km)</th><th>Early Paleogene (km)</th><th>Late Paleogene - Neogene (km)</th><th>Total (km)</th></tr>
<tr><td rowspan="5">Offshore</td><td>Holford et al., 2005</td><td>2-3</td><td>1-2</td><td>1</td><td>4-6</td></tr>
<tr><td>Floodpage et al., 2001</td><td></td><td></td><td></td><td>< 2</td></tr>
<tr><td>Green et al., 1997</td><td>< 2</td><td colspan="2">< 1.5</td><td>< 3.5</td></tr>
<tr><td>Edwards & Williams, 1993</td><td></td><td></td><td></td><td>3</td></tr>
<tr><td>Colter, 1978</td><td></td><td></td><td></td><td>2</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td rowspan="3">Onshore</td><td>Mikkelsen & Floodpage, 1997</td><td></td><td></td><td></td><td>2</td></tr>
<tr><td>Evans et al., 1993</td><td></td><td></td><td></td><td>2.2</td></tr>
<tr><td>Plant et al., 1999</td><td></td><td></td><td></td><td>1.5-2</td></tr>
</table>

Colter (1978) indicates that the likelihood of good reservoir properties within the deeper parts of either basin is not likely based on the burial history.

6.7.1.1 Oil Maturation History

Oil maturation can also give an indication on the burial conditions within a basin and compliments burial curve and thermal modelling of a basin. The presence of hydrocarbons can also affect diagenesis. The maturation history of the EISB is better understood given the large deposits of oil and gas that have been discovered. Two generation phases have been identified in the Douglas, Hamilton/Hamilton North and Lennox fields, the first occurring prior to Early Cretaceous uplift. Exhumation during the Cimmerian event may have led to structure breaches and migration of hydrocarbons (Haig et al., 1997). However, further burial and non-burial effects (hot circulating fluids associated with the Fleetwood Dyke swarm emplacement) during the Cretaceous returned EISB source rocks to oil and gas generation conditions (Green et al., 1997; Haig et al., 1997; Holford et al., 2005). Green et al. (1997) indicate the peak generation of oil and gas within the Cheshire Basin occurred prior to Early Cretaceous inversion (mid to late Jurassic) and as such hydrocarbons were likely lost due to structure breaches. The lack of proven hydrocarbon resources within the Cheshire Basin has been further explored by Mikkelsen and Floodpage (1997). Whilst they conceded that the existence of a resource could not be written off due to the lack of well data and exploration in the basin, work completed by Floodpage et al. (2001) indicate the major control on hydrocarbon generation is the extent of Namurian source rocks (shales). A small amount of gas generation may occur from Westphalian Coal Measures but within the Cheshire Basin it is thought unlikely to form a large resource. Westphalian subcrop is not found to underlie the entire Cheshire Basin area producing a further limitation on generation as seen on Figure 6-9 (Mikkelsen and Floodpage, 1997). Coupled with the lack of trapping structures (the Manchester Marl and

Mercia Mudstone Group are more variable in their facies and are likely to be leaky), the hydrocarbon prospectivity of the central Cheshire Basin is poor.

The EISB has a different burial and maturation history to that of the surrounding offshore basins (Central Irish Sea Basin, Kish Bank Basin, Peel Basin and the Solway Basin). Floodpage et al. (2001) indicate the reason for the hydrocarbon success in the EISB is twofold. Firstly the source rock (Namurian shales) is well developed in the EISB. Namurian strata underlying the other basins are variable. In the Peel and Solway basins the Namurian was increasingly arenaceous with deltaic or marine facies dominating, thus limiting oil generation. In some areas erosion has removed the Namurian completely. The CISB appears to have seen non-deposition throughout and the Namurian is absent. Secondly, the burial and exhumation history favours hydrocarbon production in the EISB. The two main phases of uplift (Cimmerian and Tertiary) are seen in all basins, but the magnitude of the earlier Cimmerian inversion event is to a lesser extent in the EISB. This inversion allowed not only the preservation of trapping structures, but also a return to hydrocarbon generation during the Late Cretaceous due to resumed burial depth and increased localised heating in the Tertiary.

6.8 Basin Evolution: Structure

The Cheshire Basin and EISB are linked to a wider chain of basins that developed in a NW-SE orientation stretching as far north as the Highland Boundary Fault and as far south as the Cheshire Basin (Jackson and Mulholland, 1993). It is bounded along the southeastern margin by the NNE-SSW curved Wem-Bridgemere-Red Rock Fault System (normal fault) where the estimated throw is, at maximum, approximately 4000 m (Chadwick, 1997; Plant et al., 1999). Plant et al. (1999) state the Cheshire Basin is heavily faulted with approximately 600 seismically resolved individual faults/fault segments present, a view echoed by Rollin et al. (1995), displayed on Figure 6-25. Given the sparsity of the dataset utilised in the central parts of the basin, more are likely to exist. Rollin et al. (1995) indicate throw on most faults across the Cheshire Basin vary from <25 m to >1000 m. The western margin is relatively un-faulted and displays on-lap along its length. The Wirral forms a link into the EISB that is similarly comprised of a series of graben and half grabens (Figure 6-26). The controlling normal faults are dominantly N-S/NE-SW and E-W (Chadwick, 1997; Edwards and Williams, 1993). Discussion of the tectonic regimes in place to develop structures across both basins has been discussed in Section 6.6. The style and distribution of faulting across both basins is compared further. The nature of faulting is important when assessing the likelihood they form flow barriers. These barriers can be due to enhanced cementation along the fault due to circulating brines, creation of impermeable fault rock, clay smearing in mixed lithology stratigraphy or mechanically juxtaposing permeable:impermeable strata (Edwards and Williams, 1993). The compartmentalisation of a reservoir will occur if these barriers exist, especially where multiple fault sets are present, with the likely effect being a restricted flow rate from target reservoirs. Faults across both basins have developed as per Figure 6-27 (Edwards et al., 1993; Griffiths et al., 2016), with field examples presented in Figure 6-28 and 6-29. Initial formation of solitary deformation bands have occurred with only mm scale offset, well documented by Griffiths et al. (2016) for onshore Cheshire Basin localities. These have also been noted in offshore wells in the Hamilton and Douglas Fields (Edwards and Williams, 1993). If there is continued deformation further bands coalesce into a wider zone of parallel – sub-parallel bands. A polished slip surface will eventually be generated upon continued deformation, localised at the margin of the deformed zone. The amount of deformation on the fault determines the width of the fault; larger-scale faults have larger throw associated with them that is accommodated on multiple faults. As such the width of such fault zones increases with displacement.

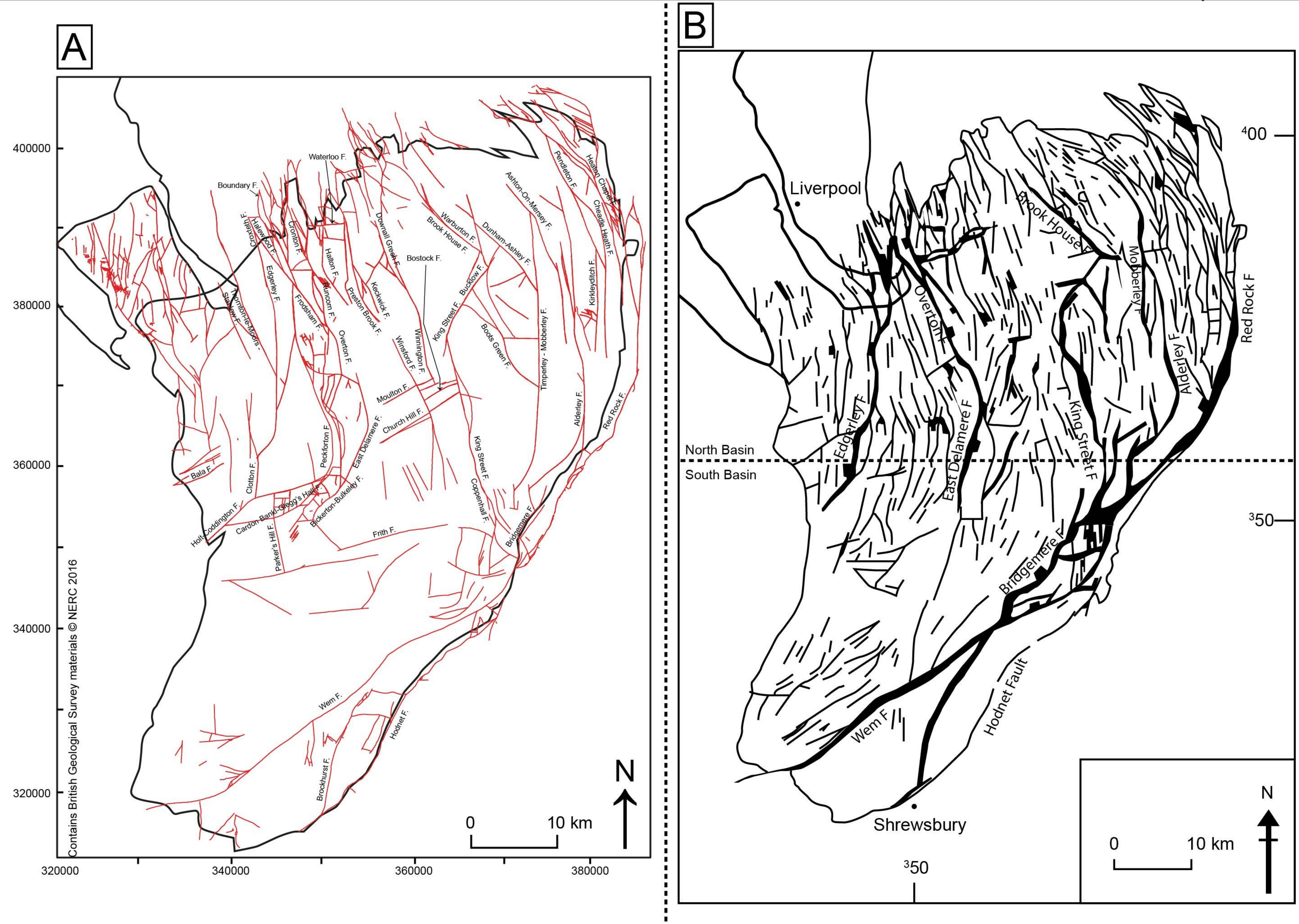


Figure 6-25: A – 1:25,000 and 1:50,000 surface faults. B – Faults located at the base-Permo-Triassic, likely base of the Collyhurst Sandstone (Chadwick, 1997).

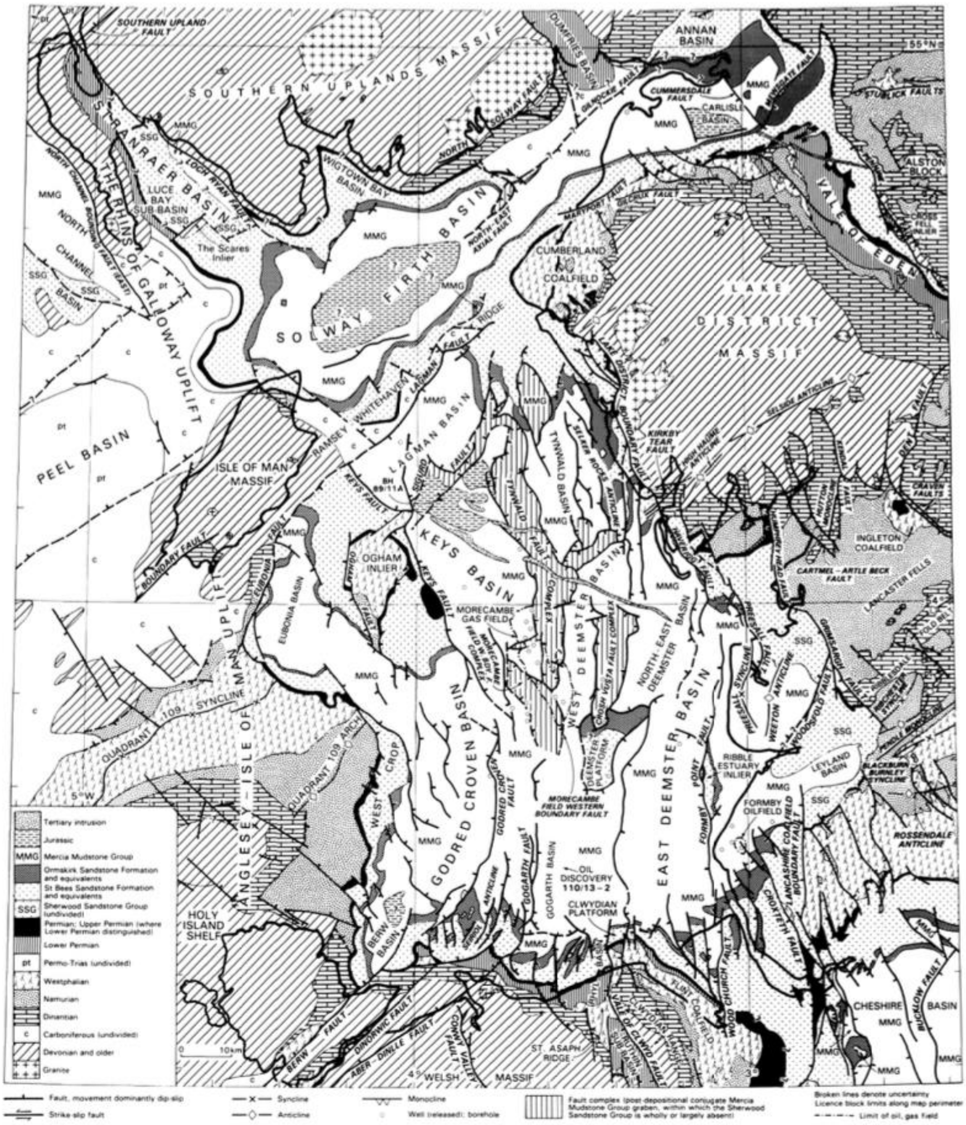


Figure 6-26: Main basins and structural elements of the EISB, omitting minor faults (Jackson and Mulholland, 1993).

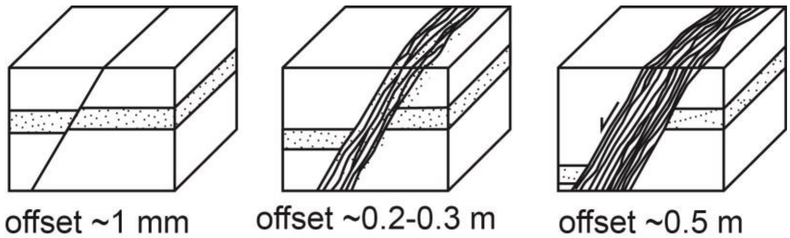


Figure 6-27: Fault formation and development in Permo-Triassic sandstones (Edwards et al., 1993).

Figure 6-28: Example of solitary cataclastic deformation band development at Frodsham, Cheshire.

Figure 6-29: Example of larger slip accommodated on multiple deformation bands at Thurstaston, Cheshire. Of note is the width and length of these deformation bands. Continued movement on this plane would ultimately lead to the development of a slip surface.

The implications for fault zone width are reduced permeability, transmissivity and ultimately compartmentalisation of reservoirs as witnessed in the offshore Douglas Field; a fault-terraced field with limited communication between each segment (Figure 6-30). Fault seal analysis has indicated faults are laterally sealing in deeper areas of the field.

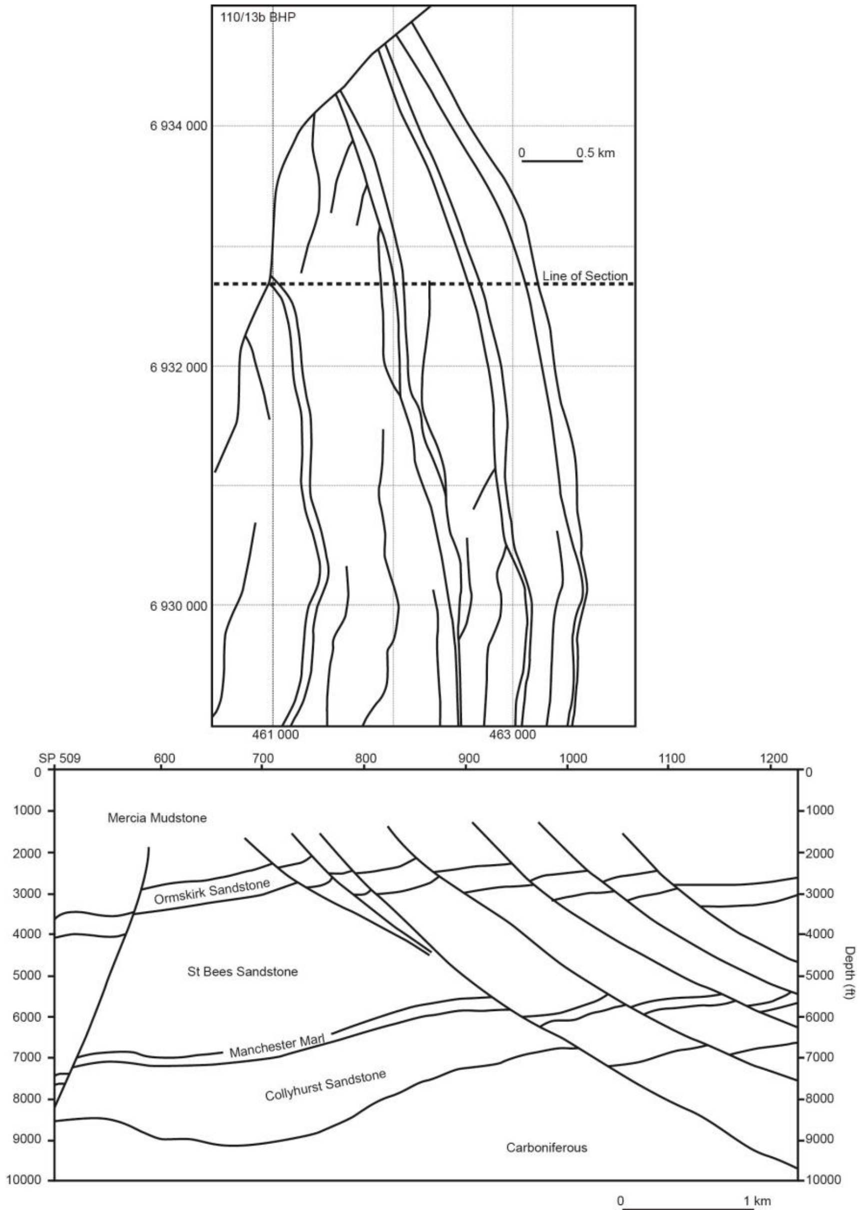


Figure 6-30: Overview of the Douglas Field structure. Faults are sealing or slightly leaky across the Field causing compartmentalisation (adapted from Yaliz and McKim, 2003).

Onshore localities such as Thurstaston (SJ 244847) and Helsby Hill (SJ 491754) indicate similar compartmentalisation occurs.

6.8.1 Fault magnitude & orientation

Edwards and Williams, 1993 and Chadwick, 1997 have categorised faults based on orientation, throw and length. Table 6-8 defines faults by their displacement that will subsequently be used throughout this Chapter.

Table 6-8: Fault classification by amount of displacement (Chadwick, 1997; Edwards and Williams, 1993).

Qualitative Fault Size	Typical Displacement (m)
Small	<1-50
Medium	50-500
Large	500-1000
Basin Bounding	500-2500+

The distribution of these faults across both basins is described as a fractal distribution (Chadwick et al., 1995; Plant et al., 1999) indicated in Figure 6-31. Deviation away from a fractal distribution for faults with <100 m throw is attributed to under-sampling by Plant et al. (1999). For large scale (basin-bounding) faults the deviation may be due to the tendency to preferentially transfer displacement onto smaller faults; large scale faults are rare as a result.

Dominant fault orientations are summarised for both basins as follows:

- **North-South trending**: dominate across the northern Cheshire Basin and offshore EISB, likely formed perpendicular to the main basin extension orientation (E-W). These are largely small to medium dip-slip faults that are regularly distributed across the northern part of the basin indicating a possible lack of basement control due to heterogeneities within the basement (Chadwick, 1997).
- **Northeast-Southwest trending**: dominate the southern Cheshire basin. The orientation indicates a strong basement control when compared with the northern basin and offshore EISB. These faults are oblique-slip in nature and are concentrated along the major basin bounding faults. There are few small-medium faults seen in the intervening areas between these major faults; they are concentrated around the major fault planes (Chadwick, 1997).
- **East-West trending**: these faults are generally small to medium sized faults and are again found more dominantly within the north Cheshire Basin and EISB.

6.8.2 Fault thickness and displacement

Fault zone width and displacement amount are related; the greater amount of displacement increases the width of a fault zone. The fault zone width:displacement relationship has been quantified for onshore Cheshire Basin localities by Knott (1994) and Beach et al. (1997), with data shown in Figure 6-31.

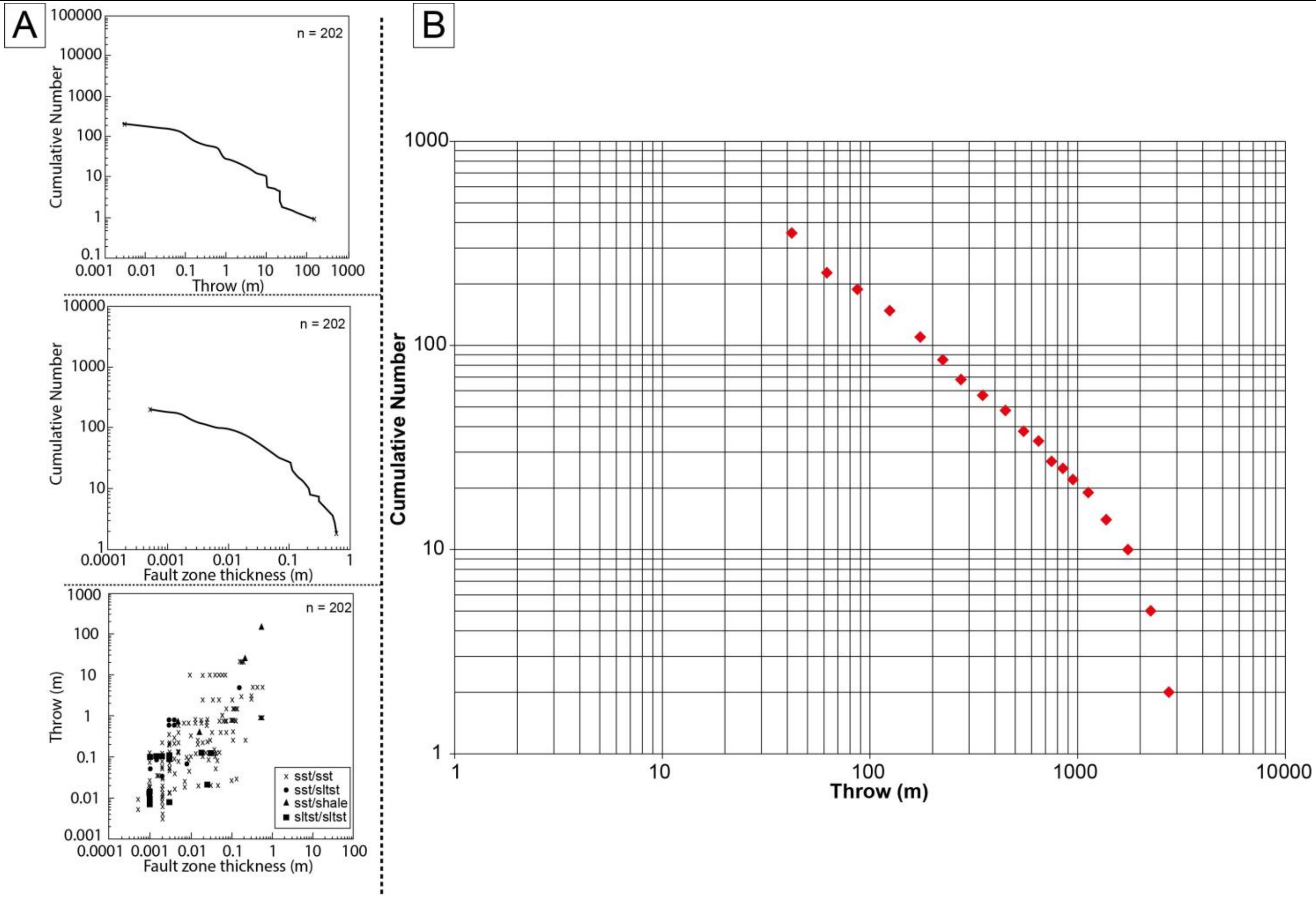


Figure 6-31: A – Relationship between fault throw, zone thickness and cumulative number (adapted from Beach et al., 1997). B – Fault throw vs cumulative number displaying a mostly fractal distribution (Plant et al., 1999).

Knott (1994) also identified the link between fault width and displacement but notes there appears to be thresholds at 0.3 m and 0.5 m displacement that see fault zone width increase disproportionately.

6.8.3 Porosity reduction

Griffiths et al. (2016), Edwards and Williams (1993) and Beach et al. (1997) discuss the porosity and permeability across these faults in both basins, as both display similar trends. Both the Sherwood Sandstone Group and Collyhurst Sandstone are sandstone-dominated sequences resulting in cataclastic deformation bands being created. Griffiths et al. (2016) shows the process is a grain-size controlled process at Thurstaston; coarse aeolian (quartz arenite) sandstones contain more deformation bands than finer fluvial (sub-arkosic) sandstones. A secondary control relates to mineralogy. Porosity in deformation bands is largely reduced as a result of cataclasis and cementation. In coarse aeolian sandstone facies a reduction from 26% to 10% was measured in the deformation band whilst in finer fluvial facies a reduction from 11% to 4% was seen. Cementation further affects porosity and is discussed within Section 6.9.

6.9 Basin Evolution: Diagenesis

Diagenesis can be summarised as the physical and chemical changes sediment undergoes after deposition (Nichols, 2009). Diagenetic processes can be both detrimental and beneficial to preservation of high reservoir quality. Data presented in Section 6.7 indicate both the Cheshire Basin and EISB have been through at least two major deep burial and exhumation phases indicating there is a high risk of complex diagenesis. Figure 6-32 shows the typical temperatures and pressures over which diagenesis occurs.

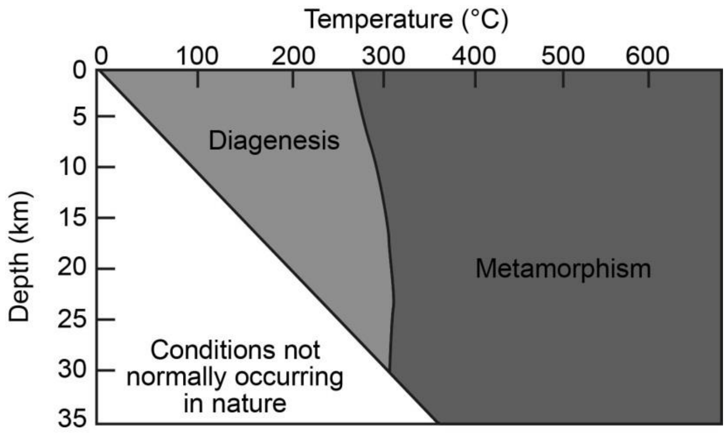


Figure 6-32: Range of temperature and pressures under which diagenetic processes occur (Nichols, 2009).

Currently target reservoir rocks are situated 3-4.5 km depth within the Cheshire Basin, but they have potentially been subjected to 6 km burial depth during basin formation. Identifying diagenetic effects from samples at shallower depths within the EISB, combined with data from the Cheshire Basin, may allow some prediction of reservoir quality at greater depths. It allows an assessment of potential permeability barriers that may affect the overall connectivity of target reservoirs especially where diagenesis has been concentrated along faults/fractures planes. It also allows the identification of facies that are more or less susceptible to degenerative diagenetic phases.

Section 6.9 aims only to provide a broad overview of the diagenesis encountered, and the distribution across facies, to facilitate a discussion on how diagenesis has and will affect the target strata of the Sherwood Sandstone Group and Collyhurst Sandstone within the deeper parts of the Cheshire Basin. In addition it is noted that data from oilfields must be treated with caution when comparing with onshore analogues. The presence of hydrocarbons may inhibit precipitation of cements thus modifying the reservoir (Bloomfield et al., 2006; Gluyas et al., 1993).

6.9.1 General Diagenetic Overview of Permo-Triassic Sandstones

A summary of the general diagenetic trends seen within UK Permo-Triassic sandstones has been produced by Tellam and Barker (2006).

- Early diagenesis: Precipitation of illite, feldspar, carbonates (non-ferroan), haematite and gypsum.
- Burial diagenesis: Compaction occurs to a greater extent in sandstones that do not have early cementing phases. The majority of Permo-Triassic sandstones maintain porosities of 20-30% suggesting early cement phases occurred frequently in these rocks.
- After inversion of Permo-Triassic basins, further diagenesis has occurred with dissolution of carbonate and sulphate phases and weathering of feldspar to clay.

Within the Cheshire Basin and EISB, more specific diagenetic effects have been assessed by several authors. Along with a more generalised diagenetic assessment of the EISB from current literature, specific diagenesis within the Douglas, Hamilton, Hamilton North and Lennox field has been assessed from data held by ENI and Greenwood and Habesch (1997). Data from the Cheshire Basin has been obtained from literature and also from ENI and is compared with EISB data to determine whether diagenetic phases and their distribution across target reservoirs are similar.

6.9.2 Sherwood Sandstone Group: Compaction-based effects

The conclusions from Edwards and Williams (1993) regarding the onshore Sherwood Sandstone Group are that compaction effects are weak within the EISB and the Cheshire Basin, a view echoed by Meadows and Beach (1993). Haig et al. (1997) also state within the Lennox field porosity loss due to compaction is also minor. In particular samples from onshore outcrops of Permo-Triassic sandstones show no induration and grain contacts are not seen to be sutured. Meadows and Beach (1993) demonstrate high minus cement porosity is seen in both fluvial and aeolian sand units within the EISB. Long grain contacts are also observed but on a small scale. They state an early framework cement may have helped to stabilise porosity thus reducing the effect of compaction, a view also shared by Edwards and Williams (1993). The original cement phase has subsequently dissolved and in some areas has been replaced by a variety of secondary minerals such as calcite, dolomite and iron oxide (British Geological Survey, 1997). Compaction, therefore, does not appear to be a limiting factor on reservoir quality assuming an early framework cement was present during early burial.

6.9.3 Sherwood Sandstone Group: Grain Type / Sorting Effects

The Sherwood Sandstone Group (in particular the Helsby Sandstone and equivalents) have been grouped into distinct lithofacies by several authors detailed in Table 6-9 (Bloomfield et al., 2006; Cowan, 1993; Meadows and Beach, 1993; Yaliz and McKim, 2003; Yaliz and Taylor, 2003).

Table 6-9: Lithofacies of the Helsby Sandstone / Ormskirk Sandstone.

Meadows & Beach, 1993 EISB	Bloomfield et. al, 2006 Cheshire Basin (Helsby & Wilmslow Sandstone)	Cowan, 1993 EISB (Morecambe)	Yaliz & McKim, 2003 Yaliz & Taylor, 2003 EISB (Lennox, Douglas, Hamilton)
Fluvial channel association F1 Major fluvial channel sandstones F2 Minor fluvial channel sandstones	Aw Aeolian sandy sabkha	A Major channel fill	A1 Aeolian dune
Aeolian facies association A1 Aeolian dune sandstone A2 Aeolian sandsheet sandstone	A1 Aeolian sandsheet	B Ephermeral channel fill	A1 Aeolian sandsheet
Sheetflood facies association S1 Sheetflood deposits	Ax Aeolian dune	C Non-channelized sheetflood	S1 Aeolian sabkha / sheetflood
Playa facies association P1 Playa lake deposits P2 Playa margin deposits	Fx Coarse-grained fluvial channel fill	D Non-reservoir fines - abandonment	F1 Fluvial channel
	F1 Fine-grained fluvial channel fill	E Non-reservoir fines - playa	F2 Fluvial abandonment
	M Mudstone	F Aeolian dune and sandsheet	P1 Playa lake/floodplain
	Sm Massive sandstone		

These lithofacies have further been discussed with respect to the effect of diagenesis. In general aeolian sandstones display better sorting than fluvial and sheetflood sandstones (Meadows and Beach, 1993). Whilst fluvial and sheetflood sandstones display poor to moderate sorting throughout their full sequence, aeolian sandstones can display a bimodal split in sorting. Whilst some individual laminae are well or very well sorted, the overall unit tested can still be described as poorly sorted. With regards grain angularity and sphericity aeolian sandstones are markedly different from fluvial and sheetflood sandstones. Aeolian grains are very well rounded and have a higher level of sphericity and display open grain-floating textures (Cowan, 1993). In contrast, fluvial and sheetflood grains are angular to sub-angular (occasionally sub-rounded) with a tendency for low sphericity.

The sorting, angularity and sphericity of each facies has affected the distribution of quartz cements. Meadows and Beach (1993) argue the increased angularity and lesser sphericity in fluvial and sheetflood facies will provide more zones where pressure solution could occur during burial. The free silica released as a result could then be re-precipitated as quartz overgrowths. As a result these facies will see a greater degradation in reservoir quality and is a feature that is not affected by location.

6.9.4 Sherwood Sandstone Group: Cements

In general the dominant diagenetic phases seen within offshore samples were listed as the following (Meadows and Beach, 1993):

- Clay (illite, some kaolinite and mixed illite-smectite).
- Carbonates (both ferroan and non-ferroan calcite and dolomite).
- Quartz.

The cementation of the Sherwood Sandstone Group both onshore and offshore has been described as having early (eogenesis), intermediate (mesogenesis) and late (telogenesis) stages (Edwards and Williams, 1993; Plant et al., 1999; Yaliz and McKim, 2003; Yaliz and Taylor, 2003). Figure 6-33 and 6-34 provide an overview of onshore and offshore diagenesis. It should be noted that Figure 6-33 does not include specific information regarding fracture mineralisation. This aspect is discussed within Section 6.9.5.

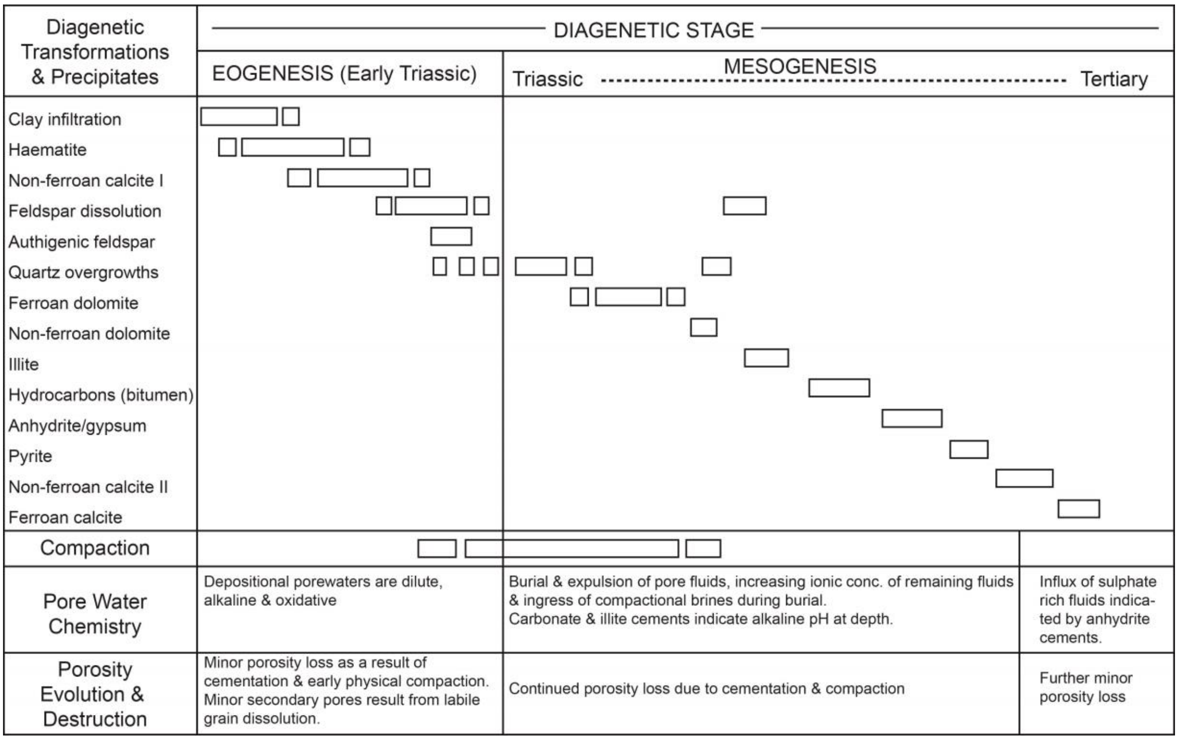


Figure 6-33: Typical offshore diagenetic history of the Helsby Sandstone (upper Sherwood Sandstone Group) that is seen across the southern EISB (Haig et al., 1997).

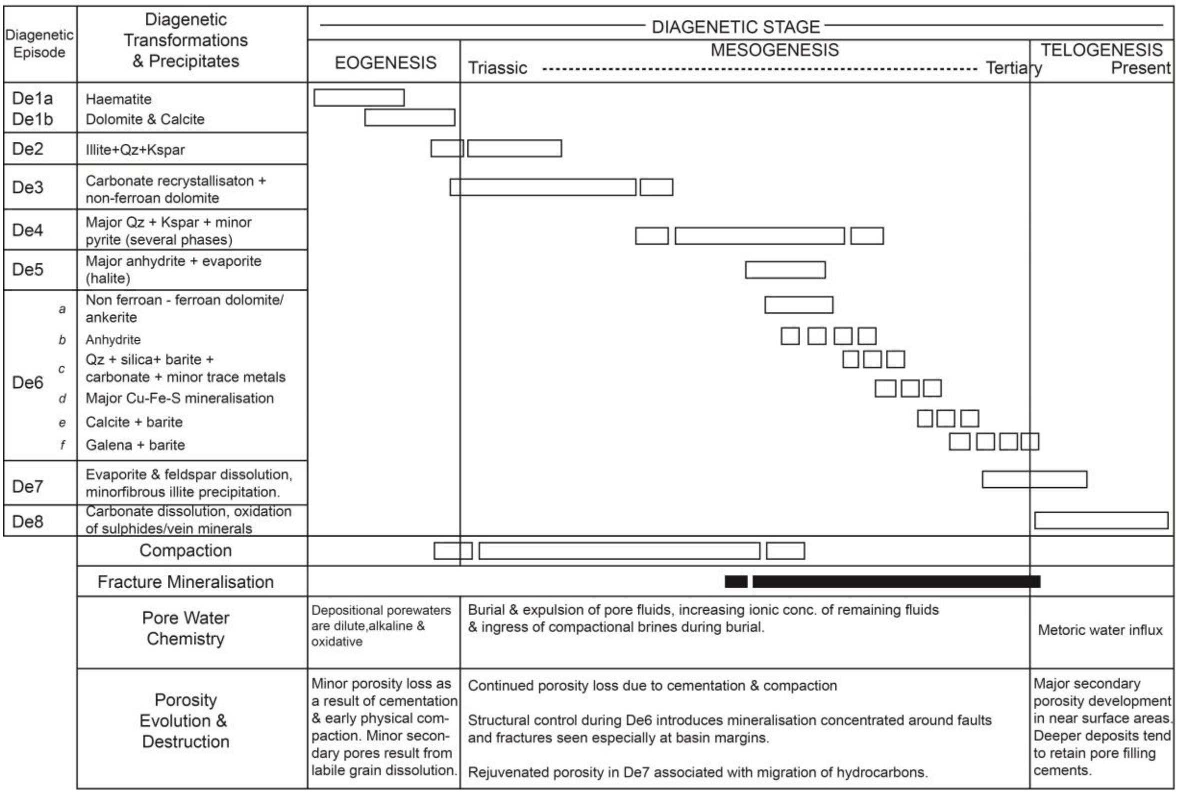


Figure 6-34: Onshore diagenetic sequence for the Sherwood Sandstone Group compiled from Plant et al. (1999).

A burial diagenetic regime for both basins was described by (Edwards and Williams, 1993), summarised below.

a) **Early stage**: Semi-arid conditions prevailed across both basins. Early meteoric waters were weakly alkaline promoting the formation of carbonate cements along with some dissolution of feldspar and clay precipitation on grain surfaces. Clay cements are considered almost absent (Plant et al., 1999; Yaliz and Taylor, 2003). Given the oxidising nature of the environment, haematite coatings are also seen (Haig et al., 1997). This early cement limits compaction and grain suturing with minor quartz and feldspar overgrowths only (Yaliz and Taylor, 2003). Other minor (1-3% content) authigenic minerals noted to occur are feldspar, gypsum, anhydrite, pyrite, illite, chlorite and halite. Cowan (1993) also notes an early stage carbonate or evaporite phase within aeolian sandstones has preferentially increased the preservation potential of such horizons.

b) **Intermediate stage**: Formation of calcite, dolomite and illite due to an increasing ionic content of insitu pore fluids.

c) **Late stage**: Sulphur-rich pore water likely sourced from the evaporitic Mercia Mudstone Group increased the ionic content of pore fluids and allowed the formation of gypsum, anhydrite and halite (Plant et al., 1999; Yaliz and McKim, 2003; Yaliz and Taylor, 2003). Faulting during the Cimmerian inversion allowed these saliferous brines to further percolate into the underlying Sherwood Sandstone Group. A return to burial allowed these fluids to heat and circulate producing pore-filling anhydrite. Quartz overgrowths are also seen.

d) Within the EISB, the formation of oil has arrested diagenesis within the oil leg of reservoirs. The water leg of reservoirs has seen a very late stage non-ferroan calcite cement, likely caused by a change in the origin of pore fluid on exhumation.

Onshore diagenesis is comprehensively discussed by Plant et al. (1999) and summarised on Figure 6-34. The apparent disparity between offshore and onshore sequences is partly a function of sampling area; outcrop-scale sampling areas are accessible onshore which allows a more comprehensive sampling regime to be implemented.

Meadows and Beach (1993) have shown slight variation in cement phases exists between the facies which is linked to the initial composition of these strata, for instance lithic clasts and detrital clay within sheetflood facies, caliche in fluvial facies and reworked clasts. Localised cementation is observed around these features as a result. Aeolian sandstones are less affected by these diagenetic phases. Ponding of fluids at major stratigraphic boundaries has been noted to occur, notably at the Wilmslow Sandstone-Helsby Sandstone junction and the Chester Pebble Beds-Wilmslow Sandstone junction. In the former example it is proposed calcareous rip up clasts with the overlying Helsby Sandstone have provided a source of carbonate, the effect being preferential cementation at the junction between the Chester Pebble Beds and Wilmslow Sandstone. Later stage barite cement further occludes porosity in here. A widely distributed silicified zone typifies the latter example.

Strong reducing conditions are associated with hydrocarbons, the effect being initial corrosion of cements followed by inhibition of further cement growth. Where there are residual hydrocarbons there is the possibility of evaporitic cements forming subsequently but otherwise porosity may be maintained. The timing of hydrocarbon charge and migration then becomes important.

6.9.5 Fault related cementation: the Sherwood Sandstone Group

A regional-scale diagenesis can be witnessed across both basins. However, these burial-related diagenetic phases are also interspersed with fault-related diagenesis. In the initial formation of a discontinuity surface there may be enhanced flow along its length;

fracture flow is typically greater than matrix flow and large volumes of fluids can be pulsed through a reservoir sequence. However, diagenesis associated with these fluids is likely to occur creating pore-occluding phases and enhance cementation thus reducing permeability in the vicinity of the discontinuity. What was once a conduit for fluids now becomes a barrier in both a vertical and horizontal sense.

Fluid movement associated with faulting and fracturing has caused variation in the distribution of cement phases seen across the basins; increased cementation around faults is noted both offshore and onshore. The effect of fault related cementation can be manifested as either preferential cementation of stratigraphic horizons and/or direct cementation of the fault plane and immediate surrounding area. Both cementation styles have implications regarding the connected volumes of reservoir quality sandstones. Fault cement phases include anhydrite, gypsum and barite. The former two are likely sourced from the overlying saliferous Mercia Mudstone Group. The latter is inferred to be sourced from basement or Carboniferous strata (Naylor et al., 1989). A series of heavy mineral emplacement phases are also seen onshore along basin margins, notably at Alderley Edge, where Cu-Fe-Pb-S minerals are concentrated along faults and fractures (Plant et al., 1999; Rowe and Burley, 1997).

Preferential cementation of aeolian and some coarser fluvial sandstones occur adjacent to fault planes within both basins because of their enhanced poroperm properties; quartz overgrowths, barite and anhydrite are found as pore occluding phases in aeolian and coarse fluvial sandstones. The presence of initial quartz overgrowths and later-stage barite indicate several fluid flushing events have occurred along fault planes. A structural as well as stratigraphic control on diagenesis can be inferred. The pervasiveness of cementation is related not only to width, spacing and throw on the fault surface, but is also controlled by variation in grain size and original porosity and permeability of the sandstone.

6.9.5.1 Permeability & transmissivity across faults

The importance of faulting across the basin lies in their ability to create permeability barriers or to produce conduits for preferential flow; both are important in understanding a geothermal system. Within both basins it is evident that diagenesis associated with faults has modified the flow properties of these structures.

Edwards and Williams (1993) carried out analyses for five facies at varying distances from selected fault planes both onshore and offshore. The results are summarised in Table 6-10.

Table 6-10: Observed porosity reduction due to fault cementation in onshore and offshore sandstone facies (Edwards and Williams, 1993).

Facies	Porosity %		
	Initial (un-altered)	Moderately cemented	Cemented (adjacent to fault)
Aeolian Dune	28	13	2
Aeolian Interdune	24	13	4
Fluvial Channel Sandstone	17	11	3.5
Fluvial Sheetflood	13	9	4
Fluvial (reworked aeolian)	18	10	3

Aeolian sandstones are most affected by fault cementation, but all facies see a porosity reduction (<4%). Further to this permeability is reduced to <1 mD in faulted zones.

The ability of faults to transmit or inhibit fluid flow across the Cheshire Basin has been assessed by Hitchmough et al. (2007), who indicate only 9% of discontinuities are flowing within the Cheshire Basin (noted to be horizontal – sub-horizontal bedding planes). Pump tests from the Wirral peninsula have shown certain N-S trending faults form barriers to flow across the area tested, and it is likely these barriers will be recognised elsewhere across the basin (Seymour et al., 2006). There is also evidence from the Wirral that where fractures sets are well developed they form transmissive flowing networks of up to 10,000 m^2 d^{-1}, but more likely 400 m^2 d^{-1} (British Geological Survey, 2002). This transmissivity is only evidenced in the shallow subsurface, however, and most likely reflect the loss of diagenetic cements and stress relief. In addition Edwards and Williams (1993) indicate faults like those seen on the Wirral are not common across the basin, and fractures are not pervasive due to their being refracted due to competency variation in the stratigraphy (they terminate in less competent mudstones).

6.9.6 Collyhurst Sandstone diagenesis

The diagenetic sequence within the Collyhurst Sandstone is not widely described as it is not penetrated to a great extent in either basin. The unit is described as being sandstone rich and of mixed aeolian, fluvial and minor sabkha origin (British Geological Survey, 2003; Edwards and Williams, 1993). Within the EISB it is described as generally displaying poor to moderate porosity and permeability. Aeolian sandstones in the Collyhurst Sandstone form the best quality reservoir target (noted to retain a porosity of 15-18%), whilst fluvial are poor quality (porosity 4-7%) due to the development of authigenic clay. Growth in clay is related to the deeper burial depths the Collyhurst Sandstone has encountered. ENI also cite primary depositional factors as being a cause of the poor quality but do not elaborate on what these factors are.

6.10 Basin Evolution: Summary

The data presented within Sections 6.6-6.10 indicate that the basins are broadly comparable but do display some differences. Both basins evolved synonymously throughout the Permian and Triassic and display the same facies variation on an inter- and intra-basin scale. Burial histories are similar, the magnitude being slightly greater in the Cheshire Basin. The resulting diagenesis shows comparable trends across both the basins. In a similar manner to the intra- and inter-basin heterogeneity seen in facies, a similar trend can be seen in the diagenesis of sediments. Fault patterns across the northern Cheshire Basin are comparable to the fault pattern that extends offshore. The southern Cheshire Basin shows a variation in fault spacing and orientation when compared with the north Cheshire Basin and EISB; it appears to be more widely spaced and on a NE-SW dominant trend as opposed to N-S. The orientation has been attributed to a variation in underlying basement. The variation in fault spacing may also be due to basement variation, but it could also be related to two other effects; glacial deposits overlie much of the southern Cheshire Basin and exposure is poor, and the scale of resolvable faults is such that they can't be identified on geophysical surveys. Despite this, all faults are likely to behave in the same manner across both basins, with fault-related diagenesis and subsequent transmissivity being similar.

From a geothermal perspective the basin comparison indicates offshore data for target geothermal horizons can be used and applied to the same stratigraphy for the onshore Cheshire Basin; the use of data from the EISB has, therefore, been used to supplement data from the onshore Cheshire Basin. Data from both basins are presented within the following Section (6.11), and where possible these data are scrutinised for suitability in predicting trends across the Cheshire Basin.

6.11 Data / Results and Analysis

6.11.1 Porosity, permeability and transmissivity data

Figure 6-35, 6-36, 6-37 and 6-38 show porosity-depth, permeability-depth and porosity-permeability plots for all data from offshore and onshore sources described in Section 6.5. Raw data can be found in Appendix F.4. Figure 6-39 compares log-derived porosity data taken from two onshore wells (Prees-1 and Knutsford-1), presented by two authors (Plant et al., 1999; Rollin et al., 1995). The point highlighted “A” has not been included in the line of best fit calculation.

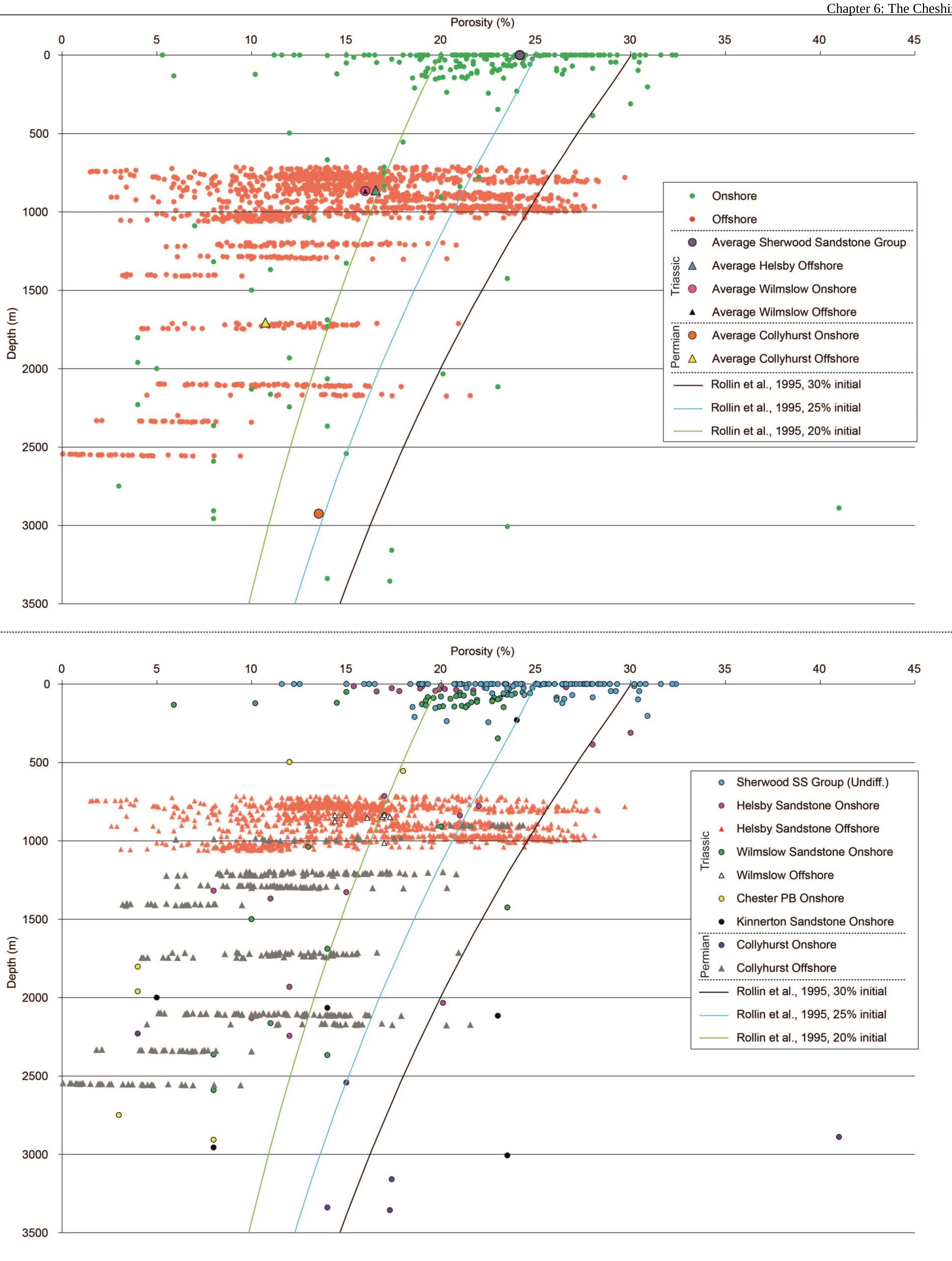


Figure 6-35: Porosity-Depth plots split by onshore and offshore data, and also by formation / age. Porosity-depth curves have been calculated using the equation stated by Rollin et al. (1995), where initial porosity at deposition has been varied (20%, 25% and 30%). Current depth is quoted, not maximum burial depth.

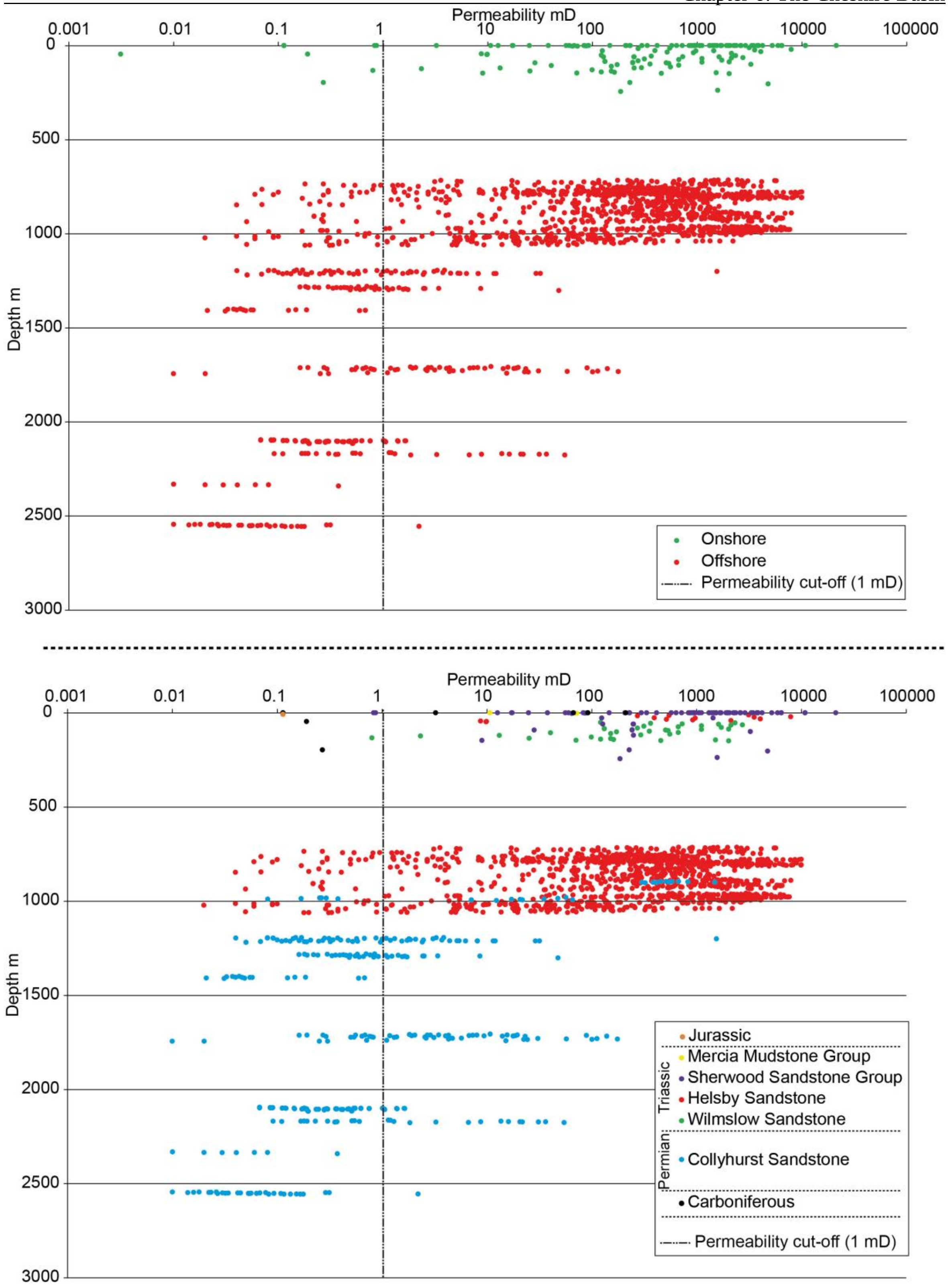
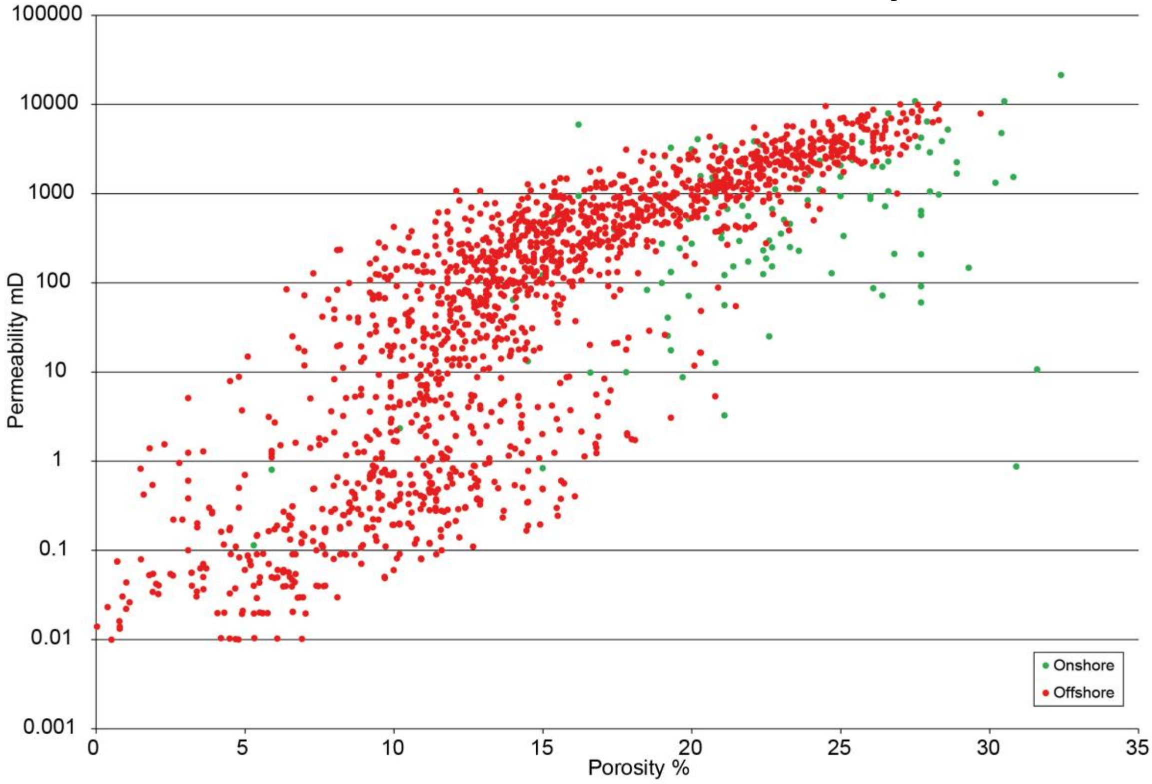


Figure 6-36: Permeability-depth plots split by onshore and offshore data, and also by formation or age. Current depth is quoted, not maximum burial depth.



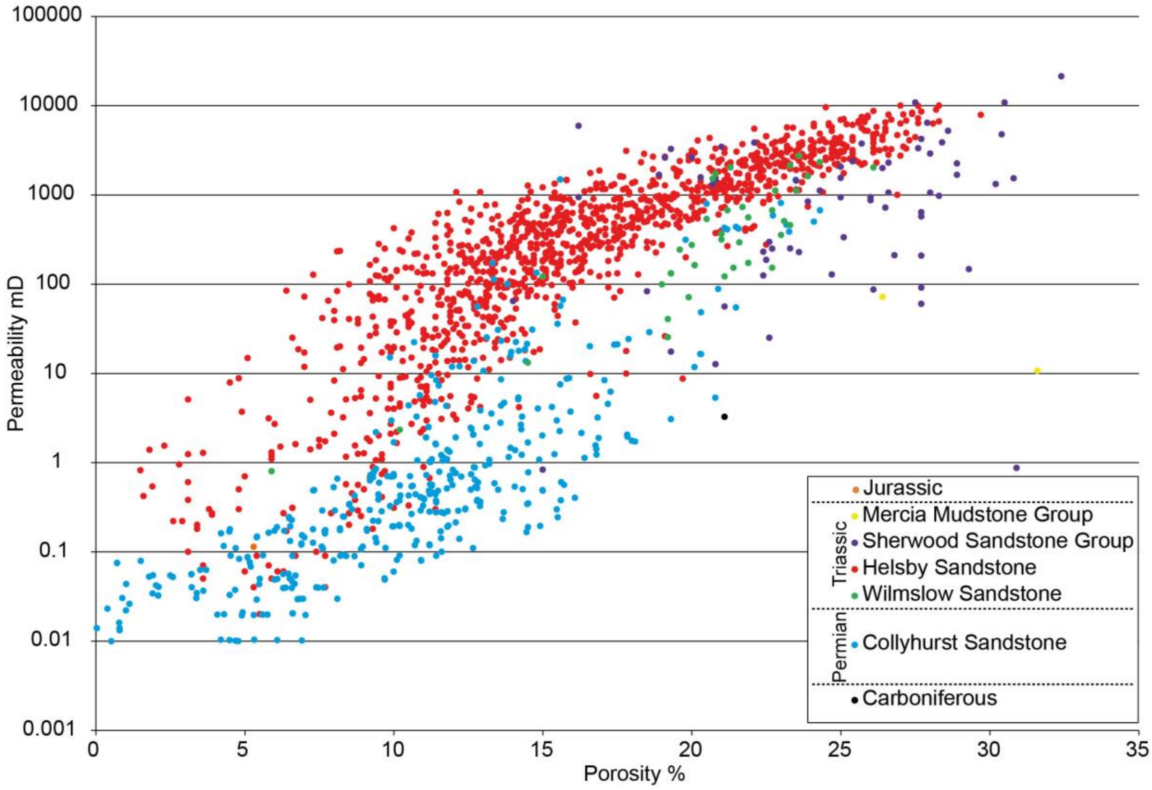


Figure 6-37: Porosity-permeability crossplots for all data split by onshore and offshore data, and also by formation or age

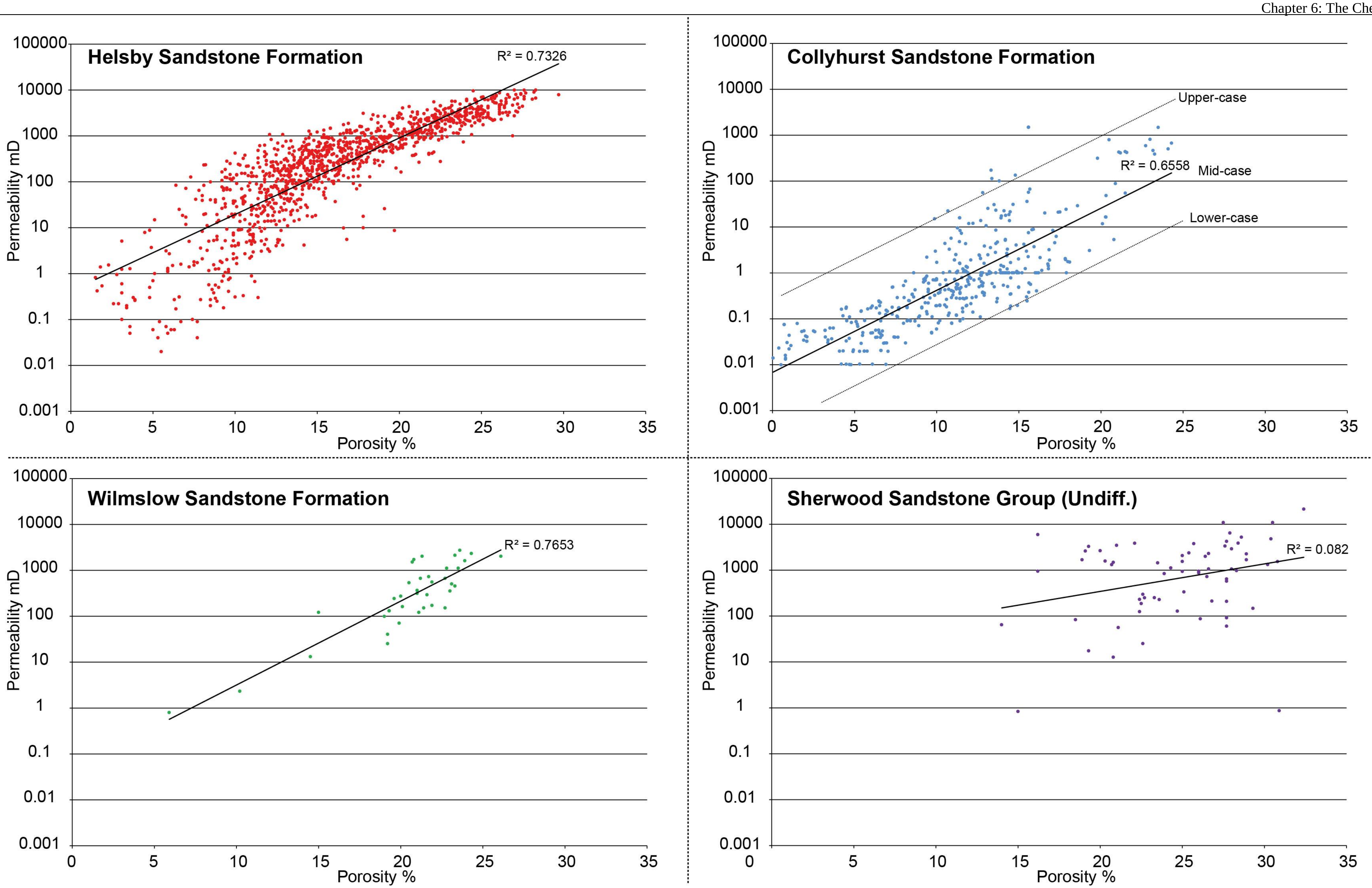


Figure 6-38: Individual porosity-permeability crossplots for the Sherwood Sandstone (onshore data only), Helsby Sandstone Formation, Wilmslow Sandstone Formation and the Collyhurst Sandstone Formation. Data were provided by ENI, British Geological Survey (1997) and Bloomfield et al. (2006). Upper and Lower Case scenarios for the Collyhurst Sandstone were based on the spread of data presented on the plot.

Figure 6-39 Porosity cut-offs for the Helsby Sandstone, Wilmslow Sandstone and Collyhurst Sandstone and associated likely occurrence of the Sherwood Sandstone Group and Collyhurst Sandstone Formation towards the depocentre of the Cheshire Basin.

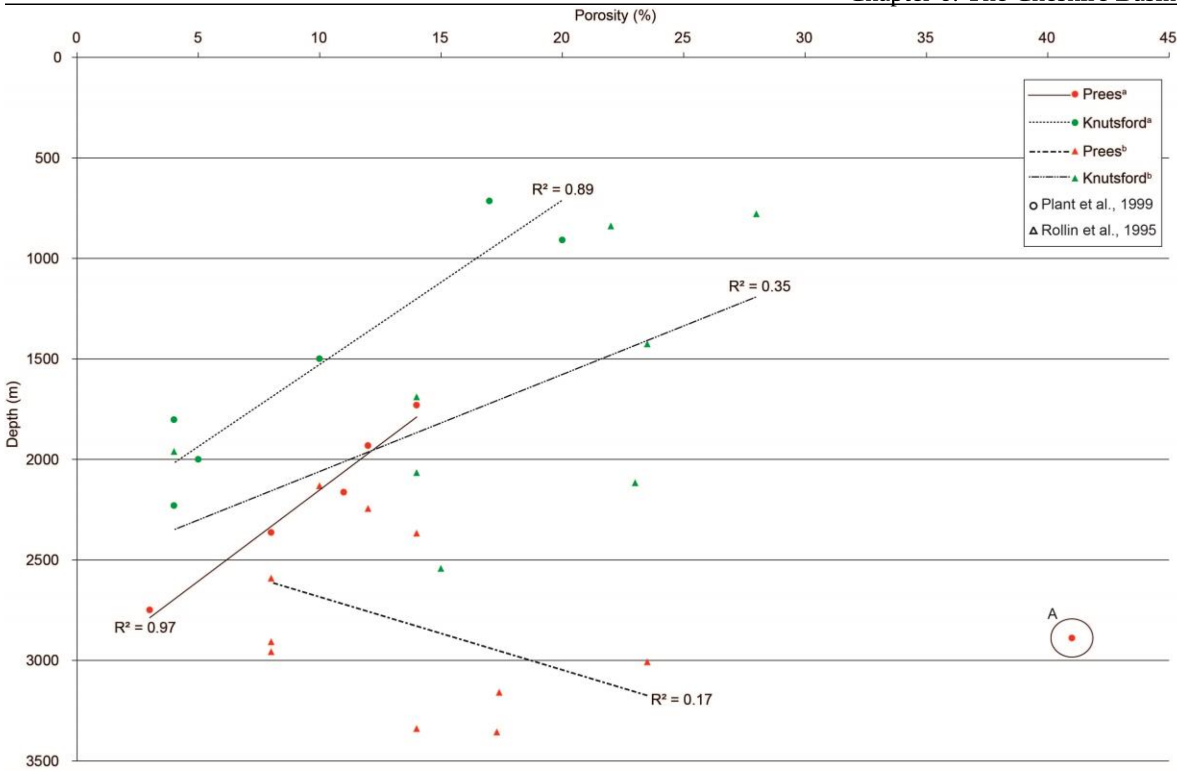


Figure 6-40: Porosity-current depth plot for Prees-1 and Knutsford-1, where [a] – Plant et al. (1999) and [b] - Rollin et al. (1995). R2 values should be treated with caution given the small number of datapoints used to correlate from.

The averaged porosity and permeability values for the combined offshore and onshore dataset are presented in Table 6-11. In addition the depth range over which values were recorded has been displayed, and also the number of values used in calculating the mean has also been presented.

Table 6-11: Averaged porosity and permeability from data displayed in Figures 6-35-6-38.

Formation/Group	Average Porosity %	Average Permeability mD	Depth Range - Porosity (m)	Depth Range - Permeability (m)	n (por.)	n (permeability)
Helsby Sandstone	16.2	1038	11-2244	11-1061	1210	1205
Wilmslow Sandstone	18.79	676	896-3356	50-150	55	38
Chester Pebble Beds	8.17	ND	11-2591	ND	6	ND
Kinnerton Sandstone	16.25	ND	230-3007	ND	6	ND
Collyhurst Sandstone	11	29	497.5-2750	896-2557	369	335
Sherwood Sandstone Group (Undiff.)	24.3	1921	<250	<250	117	80

6.11.1.1 Facies Heterogeneity

Porosity and permeability data from wells within the Hamilton field and Douglas field were used to identify facies within the upper Helsby Sandstone. Data for the Lennox Field were not available. Porosity and permeability have been plotted with respect to depth in Figure 6-41. In addition, Figure 6-42 displays cumulative permeability plotted against depth to also identify changes in facies, and also to qualitatively assess reservoir heterogeneity.

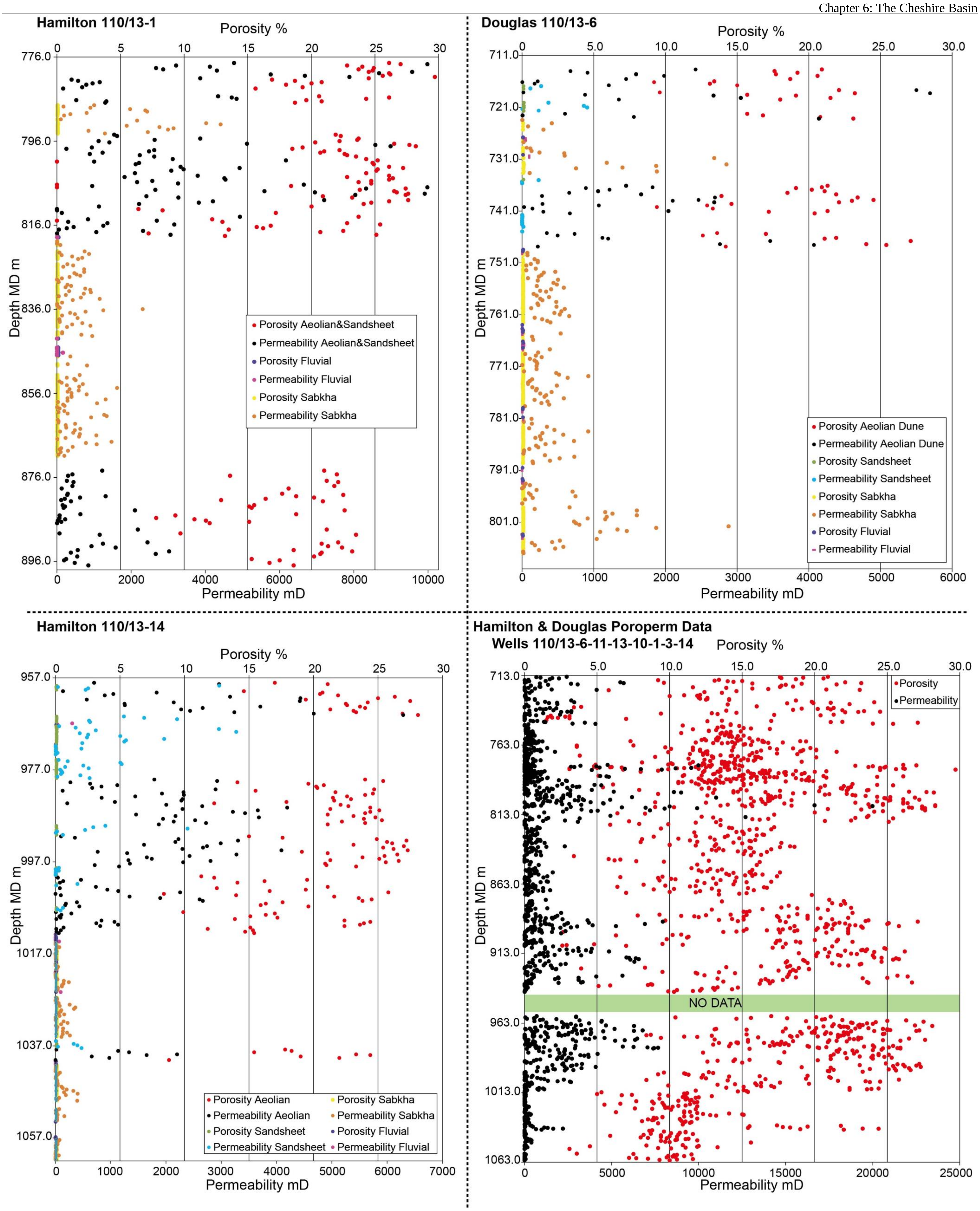


Figure 6-41: Porosity-permeability-depth plots for selected wells in the EISB. Zones of enhanced porosity and permeability can be identified which correspond with aeolian sandstone facies.

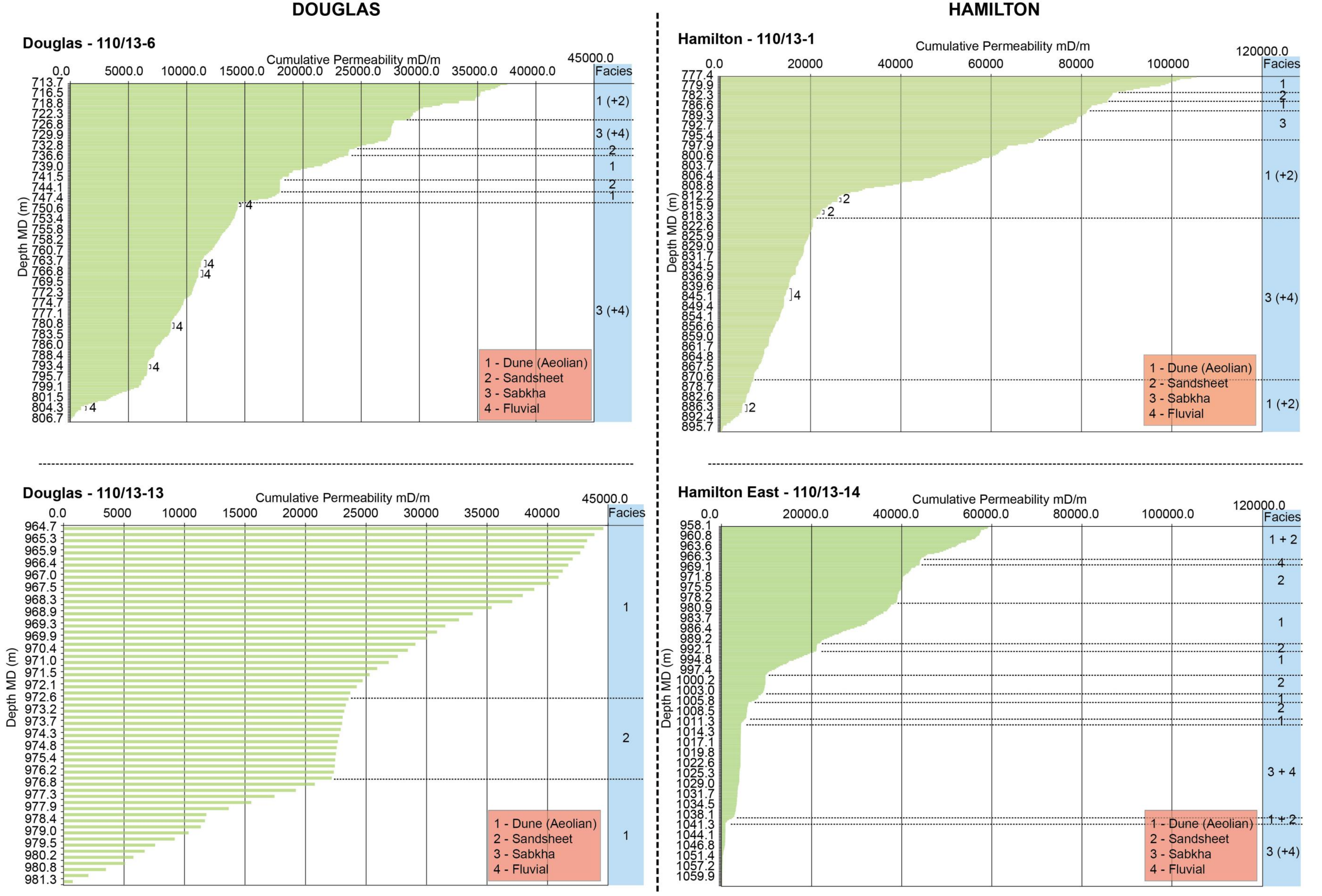


Figure 6-42: Cumulative permeability vs depth plots for wells in the Douglas and Hamilton oil/gas fields. These data are taken across the upper Helsby Sandstone Formation (Zone I, II and III) across the annotated facies

6.11.2 Aquifer Thickness

Intra- and inter-basin heterogeneity exists regarding the thickness of target aquifer strata identified in Table 6-12. For the purpose of this study the values of aquifer thickness within the Cheshire Basin are based on those recorded within the Prees-1 and Knutsford-1 boreholes. These values are to be used for calculations that relate to the rock located within the 3-4+ km depth polygon (Figure 6-8). These boreholes were drilled close to the depocentre of the Cheshire Basin where it is anticipated formations will be at their thickest. Average thickness has been used and is presented in Table 6-12.

Table 6-12: Average thickness based on Prees-1 and Knutsford-1 boreholes

	Formation	Thickness (m)
Sherwood Sandstone Group	Helsby Sandstone	425.5
	Wilmslow Sandstone	508.5
	Chester Pebble Beds	490
	Kinnerton Sandstone	158.5
Permian	Collyhurst Sandstone	514

6.11.3 Compartmentalising structures and transmissivity

Faults with recorded displacement have been identified across the basin, the locations of which are annotated on Figure 6-25. Estimated fault zone width has been derived from Figure 6-31 (Beach et al., 1997). Fault transmissivity has been calculated based on estimated permeability recorded by Edwards and Williams (1993). The results of identified faults across the Cheshire Basin are presented in Table 6-13. Table 6-14 provides a means to estimate fault transmissivity over all fault sizes.

Table 6-13: Estimated fault zone transmissivity based on the known relationship between measured fault displacement and fault zone width.

Fault	Orientation	Displacement (m)	Estimated Fault Zone Width (m)	Estimated permeability (D)		Transmissivity (Dm)	
				Min	Max	Min	Max
Clotton	N-S	300	4.5	0.0001	0.001	0.00045	0.0045
Peckforton	N-S	200	3.1	0.0001	0.001	0.00031	0.0031
Overton & East Delamere	N-S	1000	10.05	0.0001	0.001	0.001005	0.01005
Winsford	N-S / NNW	200	3.1	0.0001	0.001	0.00031	0.0031
Moulton	ENE	70	1.1	0.0001	0.001	0.00011	0.0011
Bostock	ENE	75	1.1	0.0001	0.001	0.00011	0.0011
Church Hill	ENE	100	1.2	0.0001	0.001	0.00012	0.0012
King Street Fault	N-S	1000	10.05	0.0001	0.001	0.001005	0.01005
Brook House	NW	1000	10.05	0.0001	0.001	0.001005	0.01005
Red Rock	NE-SW	1000	10.05	0.0001	0.001	0.001005	0.01005
Wem-Bridgemere	NE-SW	2500	22	0.0001	0.001	0.0022	0.022
Alderley	N-S	500	6.05	0.0001	0.001	0.000605	0.00605
Mobberley (Timperley)	N-S	1000	10.05	0.0001	0.001	0.001005	0.01005
Edgerley	N-S	1000	10.05	0.0001	0.001	0.001005	0.01005
Boots Green	NNW	150	2.5	0.0001	0.001	0.00025	0.0025
Warburton	NW	600	6.05	0.0001	0.001	0.000605	0.00605
Parker's Hill	N-S	45	1	0.0001	0.001	0.0001	0.001
Cardon Bank - Glegg's Hill	NE-SW	120	2.2	0.0001	0.001	0.00022	0.0022
Bickerley-Bulkeley	NE-SW	365	5	0.0001	0.001	0.0005	0.005
Cheadle Heath	N-S	300	4.5	0.0001	0.001	0.00045	0.0045
Dunham-Ashley	NW-SE	300	4.5	0.0001	0.001	0.00045	0.0045
Bucklow	NE-SW	300	4.5	0.0001	0.001	0.00045	0.0045
Ashton-on-Mersey	NNW	300	4.5	0.0001	0.001	0.00045	0.0045
Kirkleyditch	N-S	300	4.5	0.0001	0.001	0.00045	0.0045
Heaton Chapel	NNW	300	4.5	0.0001	0.001	0.00045	0.0045

Table 6-14: Likely estimated fault transmissivity based on various displacements, based on small, medium, large and basin-bounding fault displacements measured across the Cheshire Basin.

Displacement (m)	Fault zone width (m)	Permeability (D)		Transmissivity (D m)	
		Min.	Max.	Min.	Max.
0.01	0.001	0.0001	0.001	0.0000001	0.000001
0.1	0.007	0.0001	0.001	0.0000007	0.000007
1	0.04	0.0001	0.001	0.000004	0.00004
10	0.2	0.0001	0.001	0.00002	0.0002
100	1.2	0.0001	0.001	0.00012	0.0012
1000	10.05	0.0001	0.001	0.001005	0.01005

6.12 Discussion

6.12.1 Temperature Gradient

The temperature gradient for the Cheshire Basin has been corrected to 27°C km^{-1}, whilst offshore values indicate a gradient of 32°C km^{-1}; offshore data are uncorrected Bottom Hole Temperatures (BHTs) which indicates the measured temperature is likely to be underestimated (Busby et al., 2011). There could also be error associated with BHT temperature measurement but as shown by Hirst and Gluyas (2015) and Hirst et al. (2015b) these errors are likely to be small. The onshore value is only just elevated above the UK national average of 26°C km^{-1}. Onshore data are limited at depth and such a large correction for onshore temperatures requires discussion. The corrected value of 27°C km^{-1} is a large improvement on the original estimate and suggests whilst drilling-induced disturbance has had an effect, suppressed heat flow may play a larger part in the Cheshire Basin.

Heat flow across the Cheshire Basin is between 30-50 mW m^{-2} which is below the UK average of 52 mW m^{-2} (Busby, 2010). Richardson and Oxburgh (1978) state the reduced heat flow associated with the Cheshire Basin could be due to the presence of crust or basement that is depleted in heat generating elements. It could also, however, be attributed to the circulation of deep cooled water. Plant et al. (1999) indicate since Permian times the groundwater has been partially sourced from saline sources during marine inundations. In addition the large halite deposits in the basin also increase the salinity of circulating fluids. The density of circulating fluids is therefore enhanced, estimated to be approximately 1050 kg m^{-3}. The surface recharge is fresh water, but fluids at depth are noted to be more saline. Within deeper parts of the basin the temperature is correspondingly higher thus reducing the density and viscosity of these fluids causing an increase in circulation rates and increased perturbation of the geotherm. This flow, thought to be vigorous, could account for the suppressed measured temperatures. If heat removal through fluid movement is widespread it has implications for geothermal development in the Cheshire Basin; re-injected water may take longer to re-heat to formation temperature.

6.12.2 Porosity and Permeability

6.12.2.1 General Trends

Porosity-depth and permeability-depth data presented in Figure 6-35 and 6-36 show a similar trend; in general both parameters reduce with depth. There is a lot of scatter in the data producing a "shotgun" effect for onshore data in particular. R^2 values for all onshore, offshore and individual formations are <0.5 indicating it is unlikely compaction is controlling porosity across both basins (a view corroborated by the diagenesis seen across the basins). Further comparison of the Sherwood Sandstone Group and Collyhurst Sandstone is discussed below.

Shallow data are not considered in detail. These data are known to be largely affected by removal of diagenetic cements by groundwater and weathering which enhance porosity and permeability in these areas.

6.12.2.2 Sherwood Sandstone Group – Helsby Sandstone/Wilmslow Sandstone

Offshore porosity and permeability data taken throughout the Helsby Sandstone and Wilmslow Sandstone (Sherwood Sandstone Group upper members) overlap onshore measurements at similar depths suggesting the two datasets are complimentary at depths <1100 m; no deviations or outliers are seen between the datasets. The offshore dataset for the Helsby Sandstone display a wide range of values (<2% - 29%) reflecting the facies variation seen throughout this unit, recorded over a narrow depth interval. If individual porosity and permeability for the identified facies are plotted separately, as has been for the Douglas Field (Yaliz and McKim, 2003), the correlation improves. Similar facies are seen in onshore sections so it can be reasonably assumed that with greater sampling the same variation would be seen. If averages for offshore data are plotted alongside the published onshore values (which are themselves averages), there are no outliers. Average offshore and onshore porosity values across a similar depth interval show the offshore and onshore data plot within 2% of each other. Similarly offshore and onshore Wilmslow Sandstone values show a similar relationship albeit over a larger depth range; a reduction is seen with depth. Deeper values for the Helsby Sandstone are only available for onshore data. Porosity appears to be maintained at 10-12% up to depths of 2.3 km.

Permeability data for the Sherwood Sandstone Group are limited both onshore and offshore. Onshore data are confined to <300 m whilst the majority of offshore data are only available for the Helsby Sandstone (a small number pertain to the deeper Collyhurst Sandstone). Crossplots for the Helsby Sandstone Formation and Wilmslow Sandstone Formation (shallow onshore data) can still be used with confidence in this instance to determine porosity cut-offs for reservoir sandstones based on a pre-defined permeability cut-off. Using a 1 mD cut-off, a porosity cut-off of 2.5% is defined. The Wilmslow Sandstone Formation has a porosity cut-off of 7.5% (Figure 6-39). To determine the proportion of the Helsby Sandstone and Wilmslow Sandstone Formation that exceed these porosity cut-offs, the stratigraphy from Prees-1 has been used (Downing and Gray, 1986; Rollin et al., 1995). The Helsby Sandstone was encountered 1800-2250 m, and porosity values from both Rollin et al. (1995) and Plant et al. (1999) indicate this unit has permeability easily in excess of 1 mD and 2.5% porosity (Figure 6-39). Transmissivity based on the thickness of the Helsby Sandstone within Prees-1 (Table 6-12), for a minimum 10 mD is 4.26 D m. It is possible that the permeability for some facies will exceed 100 mD at 2-3 km further increasing the transmissivity value and thus the likelihood that the Helsby Sandstone will form a geothermal reservoir at greater depths within the basin.

The Wilmslow Sandstone is encountered approximately 2250-2400 m in Prees-1 that measured values of porosity in excess of the 7.5% cut-off. One feature of note by Plant et al. (1999) and Rollin et al. (1995) is the presence of a silicified zone within the Wilmslow Sandstone in both Prees-1 and Knutsford-1. This silicification is likely to be related to the silicified zone more commonly associated with the underlying Chester Pebble Beds, but is noted to straddle the boundary of both formations (Edwards and Williams, 1993). The thickness of the silicified zone is not defined but a zone of non-reservoir is likely to exist around the boundary of these two formations. Results are likely skewed by the silicification and as such there could still be a geothermal reservoir available. The unit is dominantly fluvial in origin so a wide range in permeability can be expected.

6.12.2.3 Sherwood Sandstone Group – Chester Pebble Beds/Kinnerton Sandstone

There are no offshore data for the Chester Pebble Beds and Kinnerton Sandstone Formation. Deep (>600 m) onshore data are limited to that measured in the Prees-1 and Knutsford-1 boreholes. With regards the Chester Pebble Beds the unit is silicified at depths >1878 m reducing average porosity to <6% (Plant et al., 1999; Rollin et al., 1995). The silicification is widespread and has been documented in well 110/8-2 over 120 km west of Prees-1 (Colter, 1978; Edwards and Williams, 1993). On this basis it is considered the Chester Pebble Beds will form a vertical barrier to fluid movement and will not form a reasonable geothermal resource target at these depths. It may form an additional local resource that may only be determined upon drilling. The main implication of the Chester Pebble Beds is the lack of hydraulic continuity between the Kinnerton Sandstone and Wilmslow Sandstone Formation.

The Kinnerton Sandstone Formation data are much more ambiguous onshore. Plant et al. (1999) indicate a porosity of 5% was measured within the Knutsford-1 bore at 2000 m. They do not offer a value for the Prees-1 bore. Contrast these data with the log-derived values determined by Rollin et al. (1995), who indicate the Knutsford-1 bore has a porosity ranging between 14-23% over 2044-2188 m. A 144 m section is reported to have a mean porosity of 23%, whilst a 44 m section has a 14% mean porosity. A maximum value of 23.5% is presented for the Prees-1 borehole from a total analysed section of 173 m (2921-3094 m), which is of limited use in this instance. An 8 m interval over the same section has a contrasting porosity of 8%. These values are likely to reflect facies variation in the section, but there is still a contrasting difference in published values between Rollin et al. (1995) and Plant et al. (1999). The data are plotted on Figure 6-40 to further highlight the variation in data that will be discussed further in Section 6.12.2.4.

No permeability data are available for these data, nor are any deep pump test data. The Chester Pebble Beds are described onshore as being dominantly fluvial. In shallow settings the Chester Pebble Beds can form a promising resource. However, silicification and the effects of diagenesis at depth are likely to render the unit with low (<1 mD) permeability. Lithology appears to exert a strong control on the level of cementation with fluvial units being more affected than aeolian units (Colter, 1978). The Kinnerton Sandstone is described as an aeolian sandstone with some fluvial re-working and as such there is a chance this unit may be locally viable as a geothermal reservoir. The extent of the potential geothermal resource cannot be constrained owing to lack of permeability data, and porosity data alone cannot be relied upon to cast judgement.

6.12.2.4 Collyhurst Sandstone Formation

Where porosity and permeability data pertaining to the upper Sherwood Sandstone Group appear to compliment offshore equivalents, the Collyhurst Sandstone shows a divergence in trends. Offshore core has been tested in 11 exploration wells across the southern EISB and the resulting trend indicates a general reduction in porosity with depth. The sections tested were up to 20 m in length. If the porosity-depth curve displayed on Figure 6-35 for 30% initial depositional porosity (i.e. the curve used by Rollin et al., 1995) is utilised, all offshore Collyhurst Sandstone data lies to the left of this curve below 2.4 km, unlike onshore data.

Offshore porosity-permeability plots for the Collyhurst Sandstone are presented in Figure 6-37 and 6-38. Rollin et al. (1995) state the average log-derived onshore porosity throughout the Collyhurst Sandstone is 14%, although nearly half of the section in Prees-1 is interpreted to have porosity in excess of 20% (interval tested 3301-3575 m). The value of 41% porosity published by Plant et al. (1999) has been removed from any calculations. The value of 41% is highly suspicious given that if an initial depositional porosity of 30% has been assumed (Rollin et al, 1995), it suggests porosity has increased with burial. The limited offshore data indicate the deepest tested section (~2250 mTVD) display a porosity range of 0-9.4% over a depth interval of 14 m. Average porosity for the intervals displayed on Figure 6-35 have been calculated and are presented in Table 6-16. The value of 14.4% at 2170 m is the closest value to the average porosity interpreted by Rollin et al. (1995) at 3.3-3.5 km.

Table 6-15: Average porosity and depth range for offshore Collyhurst Sandstone intervals.

Average Porosity (%)	Average Depth (m)
3.4	2552
5.9	2338
14.4	2170
9.4	2105
7.6	1744
12.5	1721
5.9	1406
11.6	1291
12.9	1209
12.4	990
21.6	901

Using the offshore poroperm plot in Figure 6-37, for a permeability cut-off of 1 mD a porosity cut-off of 12.0% is defined. When the 12.0% cut-off is placed on the porosity-current depth plot it indicates there may be reservoir present in Knutsford-1 and Prees-1, but it is unlikely to exist offshore. Similarly a 1 mD permeability cut-off indicated on Figure 6-36 indicates only one offshore data point is in exceedance at ~2.5 km. Onshore well logs are not available for comparison with offshore equivalents. The difference in porosity lies outwith what might be considered normal error but without the onshore logs it is not possible to substantiate this further.

Log-derived porosity data published by Plant et al. (1999) and Rollin et al. (1995) for the Prees-1 and Knutsford-1 boreholes display differing trends as shown in Figure 6-40. Taking the 41% porosity value out of consideration, data presented by Plant et al. (1999) show a well correlated trend of reducing porosity with depth (not dissimilar from offshore data) throughout all formations tested within Prees-1 and Knutsford-1. The same wells have produced differing trends in data presented by Rollin et al. (1995) resulting in an apparent increase in porosity within the Collyhurst Sandstone Formation in Prees-1. These values could be taken from particularly good quality aeolian facies; the unit is described ‘millet seed’ aeolian sandstone (Downing and Gray, 1986; Rollin et al., 1995) deposited in a dominantly aeolian system (Edwards and Williams, 1993 describe it as a mixed fluvial-aeolian sandstone) where porosity is likely to have been very good. However, the values are still at odds with those measured in shallower aeolian facies in other formations. If we assume onshore data presented by Rollin et al. (1995) are “real”, and offshore data are representative of the formation, it indicates the offshore Collyhurst Sandstone Formation degrades in quality with depth whilst onshore porosity is preferentially preserved in the Collyhurst Sandstone and Kinnerton Sandstone, more so than in shallower formations. Mechanisms to preserve porosity relate to maintaining elevated pore pressure leading to overpressure, the causes for which can be rapid burial, low initial permeability sediments, mineral dewatering and migration of pressured fluids into the target aquifer (Gluyas and Swarbrick, 2004). Overpressure will dissipate unless the surrounding geology is such that it can trap and preserve it. In the Cheshire Basin setting elevated porosities are seen in the Collyhurst Sandstone and Kinnerton Sandstone, so if overpressure has developed there must be a sealing unit above these. Silicified Chester Pebble Beds and silicified Wilmslow Sandstone Formations are mentioned by Plant et al. (1999) as occurring within both the Prees-1 and Knutsford-1 boreholes that could, if laterally pervasive, form a vertical seal. Large to intermediate scale faults across the area are most likely to be laterally sealing also, providing the conditions to maintain overpressure. It is considered unlikely, however, that these conditions are present onshore. The potential within the basin is tenuous and no mention is made in any publication referring to the drilling of Prees-1 and Knutsford-1 of encountering overpressure.

The data presented here do not provide a definitive determination of likely porosity in the Collyhurst Sandstone within the deeper parts of the basin. Offshore porosity data indicate porosity in excess of 20% are unlikely to occur, more likely being <10% at 2.5 km+. These values are based on sections with limited vertical extent. However, these data are more robust as they are derived from direct measurement of core plugs as opposed to log-derived data. In addition, facies heterogeneity can be picked up in sections of similar thickness within the Helsby Sandstone, as evidenced by Figure 6-41 and 6-42. It can be argued heterogeneity within the Collyhurst Sandstone will have been sampled in offshore sections and does provide a true estimate of porosity. Onshore log-derived porosity data indicate

40-50% of the total Collyhurst Sandstone thickness has a porosity >15% which departs from offshore values taken at shallower depths. Porosity is a parameter required for geothermal resource calculation; if porosity is unlikely to exceed 10% at 3-3.5 km this will affect the resource value. It cannot at this stage be conclusively said that this will be the case, however, but must be considered if this formation is targeted as a potential resource.

The addition of permeability data from offshore samples can be used in the determination of transmissivity based on Equation 6-2. The porosity-permeability plot in Figure 6-38 has been used to determine the permeability; 1 mD (0.001 D) has been determined at the cut-off porosity of 12%, whilst 20% porosity (the value suggested by Rollin et al. 1995) would expect to achieve 30 mD (0.03 D). The thickness of aquifer was determined by Rollin et al. (1995) as being 0.25 of the total formation thickness; in this study the thickness has been averaged from the Prees-1 and Knutsford-1 boreholes and is noted to be 514 m. This produces 128.5 m of aquifer (not necessarily continuous). A range of transmissivity values have been determined in Table 6-16 for lower-, mid- and upper-case scenarios; these permeability values have been determined from Figure 6-38 (Collyhurst Sandstone) at 12% and 20% porosity.

Table 6-16: Calculation of transmissivity values at lower-, mid- and upper-case permeability values defined on Figure 6-38 for 12% cut-off porosity and 20% porosity as defined by Rollin et al. (1995).

	12% Porosity		
Permeability (D)	Lower-case 0.00008	Mid-case 0.001	Upper-case 0.03
Thickness (m)	128.5	128.5	128.5
Transmissivity (D m)	0.01028	0.1285	3.855
	20% Porosity		
Permeability (D)	Lower-case 0.002	Mid-case 0.03	Upper-case 1
Thickness (m)	128.5	128.5	128.5
Transmissivity (D m)	0.257	3.855	128.5

Estimating flow volumes as per Chapter 4 (Equation 4-2) also yields a range of values dependant on whether “offshore” (i.e. 12% porosity) values are used, or “onshore” values (i.e. 20% porosity) are used. For the range of permeability values presented in Table 6-16, flow rate has been calculated based on a formation temperature of 94.5°C at 3.5 km depth (geothermal gradient of 27°C km^{-1}), a formation pressure of 4500 psi (31 MPa) and an approximate fluid viscosity of 1 centipoise (1.00-1.03 SG), the results of which are presented in Table 6-17. Pressure data were obtained from offshore fields (Hamilton, Douglas, Lennox) and extrapolated using the pressure gradients from offshore RFT data that are available down to Collyhurst Sandstone depth. Whilst the Collyhurst Sandstone is not encountered as deep offshore as it is onshore, it is considered valid in this instance given the similarities between the basins, and in the absence of onshore data. Flow rate has been estimated using Darcy's radial flow using the same methodology detailed in Section 4.4.3 of Chapter 4, making assumptions about input parameters.

Table 6-17: Potential flow rate range based on mid-case permeability for 12% porosity cut-off and 20% porosity. These values reflect the likely average throughout the section.

	Permeability (mD)	Flow rate (m^3 d^{-1})	Flow Rate (L s^{-1})
Mid-case (“offshore”) 12% porosity	1	47.7	0.5
Mid-case (“onshore”) 20% porosity	30	1431	16.6

The difference in flow volume is large; the “offshore” scenario indicates stimulation of the aquifer would be required to obtain suitable flow volumes. The existing “onshore” estimation indicates flow volumes are comparable with the Southampton geothermal scheme. The values presented in Table 6-17 do not account for facies variation; whilst averaged values are used there are likely to be better quality facies with higher permeability values that could contribute large flow volumes. Conversely there are likely poorer quality facies.

6.12.3 Compartmentalisation of the Cheshire Basin

The data presented with regards facies variation, diagenesis, faulting and subsequent fault diagenesis has introduced potential flow barriers at depths greater than 1 km (i.e. out of the reach of surface processes) that have the potential to segregate parts of the basin. At this stage a broad analysis of the compartmentalisation is discussed here. Segregation can have an effect on the volume of reservoir that is available for resource development. Whilst not necessarily limiting the total resource it will increase the cost of development. Reservoir stimulation, multiple well completions and smart well design may be required, all of which increase the cost geothermal development.

Faults in the basin form the largest potential barrier to flow. The work undertaken by Griffiths et al. (2016) and Edwards and Williams (1993) indicate deformation bands with small amounts of displacement (mm-cm) reduce porosity and permeability to <1 mD, and are more likely to be <0.1 mD. In relatively un-faulted areas these faults are spaced 1-5 m apart and range in length from 8-80 m (Edwards and Williams, 1993). The data presented in Table 6-13 and 6-14 indicates that all faults (small, medium and large) have the ability to compartmentalise and/or severely restrict fluid flow. Where faults intersect, for instance where N-S and E-W faults intersect, compartmentalisation will be effective. Without cross-faults fluid flow becomes restricted in one direction. In the north Cheshire Basin, elongate rectangular-rhombohedral flow channels not dissimilar to the Douglas Field are likely to form in an N-S orientation; E-W flow is restricted. Leakage of faults is seen in the Douglas Field, but this relates to flow occurring parallel to slip planes within a fault (Bentley and Elliott, 2008); perpendicular flow is still restricted. The spacing of deformation bands decreases towards larger fault structures, where increased throw is accommodated on multiple anastomosing deformation bands. Cementation along these fault planes has also occurred in addition to cataclasis that further occludes porosity and reduces permeability to <0.1 mD. Flow in any direction in the vicinity of these faults is unlikely given the length (10s of km) and width (5-10 m) of such faults, and as such form major flow barriers. Edwards and Williams (1993) state these cementing effects can persist for 300 m around medium-large scale faults.

The northern Cheshire Basin appears to be well constrained with regards structures. North-south oriented elongate channels form the dominant structure, evident both from mapped structures and from seismically imaged structures. Section 6.6.2 presents information regarding the depositional environment throughout the Permian and Triassic, and indicates deposition occurred in northward-flowing fluvial and aeolian environments. Aeolian dunes and fluvial channel systems (where the better quality sandstone units will exist) are likely to also be elongate in a NNW orientation that compliments the N-S fault compartmentalised structures.

The implication of compartmentalisation is when the potential area affected by installing a geothermal well doublet is considered. Pasquali et al. (2010) state the area drained by a geothermal doublet is 22.5 km^2, achieved with dimensions of 4.7 x 4.7 km. The spacing of mappable faults on Figure 6-26 varies across the basin with more recognised in the northern half the Cheshire Basin than the south, highlighting an important issue with fault analysis particularly with the southern Cheshire Basin. The lack of identified structures may be due to the variation in basement thought to exist. However, outcrop volume is restricted in the southern Cheshire Basin and seismic imaging not only missed a large proportion of small-medium faults, but may miss them completely due to poor quality seismic data. It is therefore considered dangerous to assume to large areas in the southern half of the basin would largely be fault-free. The spacing of faults will require careful consideration when siting a well doublet, as crossing major faults will potentially be problematic. Site-specific assessment will be required to best locate the doublet. Stimulation may again be an option but would then increase the cost of the development.

6.12.4 Reservoir Tortuosity

Whilst faults have been discussed as compartmentalising features, they can also increase reservoir tortuosity. In addition both stratigraphic and diagenetic features have the ability to increase reservoir tortuosity. The latter two are unlikely to compartmentalise in the same way faults have done due to their limited lateral extent but are likely to restrict flow in a dominantly vertical direction. Low permeability facies (fluvial overbank mudstones, some playa facies) within reservoir sections can create barriers to flow, but it is demonstrated that the occurrence and pervasiveness of such facies are limited across the Cheshire Basin; facies heterogeneity is likely to slow fluid movement but not stop it.

The permeability contrast between aeolian and fluvial facies can cause further increased tortuosity. However, if managed appropriately permeability contrasts may also be of net benefit when developing a geothermal system. Figure 6-41 and 6-42 indicates that identification of individual facies within individual formations can be used to qualify the heterogeneity; the closer to a 1:1 gradient each formation exhibits, the more homogenous the reservoir. The importance of identifying facies heterogeneity is demonstrated by Cowan (1993). Flow rate from the reservoir section of the Sherwood Sandstone Group within the South Morecambe Field was assessed; the tested section is comprised of a mixed facies sandstone interval where fluvial facies form 80-90% of the total section. Aeolian facies occupy only 5-10% of the interval and have been correlated up to 10 km apart. When isolated and tested, 50-70% of the flow is shown to come from aeolian facies that are a thickness of less than 10 m. The sustainability of the reported flow rate was not tested further but is likely to decline, as vertical transmissivity is required between facies to sustain the flow rate. Within an oil field the aeolian facies in particular could instigate early water breakthrough by acting as a preferred conduit to fluid flow. Within a geothermal system, however, the permeability contrast could be used to an advantage. Re-injecting cooled water in lower permeability fluvial facies would slow the transit time of the fluid allowing it to re-heat before reaching the more permeable aeolian facies. If a doublet system is employed, fluid can be preferentially re-injected into the lower quality fluvial facies thus increasing the time taken for the fluid to reach more permeable aeolian units. This maximises the time for that fluid to re-heat to the surrounding aquifer temperature.

There are no specific data for the shortcutting effect seen in the South Morecambe Field in any of the offshore fields of interest, or within the Cheshire Basin. The idea of re-injected into fluvial facies is a simplification given the lateral pervasiveness of these units. It is a theoretical but untested idea in this instance. This could form the basis of further work within the Cheshire Basin, but it would be specific to a location and could not be assumed for the whole basin given the lack of persistence and geometry of these facies. The same could be said for the thinner better quality Aeolian units. These units may pinch out within several kilometres.

Diagenesis of sediments throughout the basin is not uniform in distribution. Diagenetically altered zones tend to pool at formation boundaries as evidenced in particular by the silicified zone within the Chester Pebble Beds and Wilmslow Sandstone. This silicified zone is the most continuous diagenetically altered unit identified within the Cheshire Basin and has implications for vertical hydraulic continuity. Diagenesis also occurs more pervasively around facies containing lithic fragments and argillaceous material i.e. fluvial, sheetflood, and some playa facies in particular may be affected by these localised diagenetic effects. They are not predictable but should be anticipated throughout the basin. Again further flow tortuosity is introduced into the basin.

Fault cementation has been discussed as forming large-scale permeability barriers to horizontal flow. Circulating fluids also invade the surrounding host rock, occluding pore space and creating non-reservoir sections. It is recognised that aeolian facies sandstones are more affected due to their exceptional porosity and permeability, whilst fluvial sandstones are affected to a lesser degree. Again the contrast in porosity and permeability within these sections provides additional vertical tortuosity.

6.13 Conclusion

- Previous resource estimates of the Cheshire Basin have been based on limited data. Offshore data for the East Irish Sea Basin can be used to supplement the onshore dataset owing to the similarities in the development (depositional environment, burial history, diagenesis, structural history) of each basin.
- Offshore porosity and permeability data support onshore data for the upper Sherwood Sandstone Group (Helsby Sandstone, Wilmslow Sandstone). These units are likely at their deepest in the southeast of the basin where they are likely to be encountered at 2-3 km. The likely estimate of porosity and permeability within these units is considered to form a viable low enthalpy sedimentary resource that requires no reservoir stimulation. A minimum transmissivity of 4.26 D m is expected from the Helsby Sandstone alone.
- Additional permeability data for the Chester Pebble Beds and Kinnerton Sandstone Formation were not available and as such the resource available within these formations remains unchanged. It is likely that the geothermal resource within the Kinnerton Sandstone Formation will ultimately reduce as it is based upon data that are not considered feasible; several deep (>2 km) porosity values depart the general trend of porosity reduction with depth.
- There appears to be divergence in the porosity and permeability data for the deeper Permian Collyhurst Sandstone target. When data for onshore wells (Prees-1, Knutsford-1) are compared, data for the two same wells have been assigned differing porosity values for the same formation. More data are available for offshore wells that indicate permeability and porosity in the Collyhurst Sandstone unit are low at 2.5 km (3.4% on average), and are likely to reduce further. Onshore data suggest an increase in porosity is seen with some values exceeding the shallower Helsby Sandstone Formation. The average onshore porosity at 3-3.5 km was determined to be 14% (Rollin et al., 1995).
- The disparity could be due to a) sampling bias b) mis-interpretation of onshore logs or c) preferential preservation of poroperm onshore. Sampling bias is thought to be limited as facies heterogeneity is seen over sections of similar thickness within the Helsby Sandstone. Mis-interpretation of onshore logs cannot be substantiated as these logs are not available for scrutiny. The preferential preservation of porosity and permeability may be caused by overpressure (not previously mentioned in literature) or by removal of diagenetic cements. There is no evidence for either of

these mechanisms to exist. Therefore, the data for the Collyhurst Sandstone is inconclusive.

- Based on offshore data it is considered that the estimated transmissivity within the Collyhurst Sandstone Formation is low (0.01 – 3.8 D m) where it is located at depths >2.5 km, well below the anticipated 5 D m quoted by Rollin et al. (1995). If onshore porosity data are used to generate likely permeability at 3.5 km, the transmissivity improves greatly (0.26 – 128.5 D m). In the former case, the geothermal resource will require further stimulation. Stimulation should be considered a possibility when designing any potential geothermal development located within the depth polygons defined on Figure 6-8 as it will increase the cost of developing such a resource.
- Flow rates indicate that if onshore data are accurate, extraction of fluid from the Collyhurst Sandstone may be comparable (if not in excess) of those obtained in the Southampton Geothermal Scheme (1431 m^3 d^{-1} / 16.6 L s^{-1}), whilst offshore data produce only 47 m^3 d^{-1}.
- At this stage the data are not definitive to support offshore or onshore data alone. This work does, however, show what ranges may be encountered and produce potential end-member scenarios for use in future development options.
- An assessment of compartmentalising features across the basin indicates most faults and deformation bands will not permit cross-flow. In relatively un-deformed areas >300 m from medium-large faults (500+ m throw), flow in the northern Cheshire Basin will be channelled in an N-S direction. This compliments the rough paleoflow direction (NW) of the sediments within the basin. Some stimulation may still be required where E-W / ENE faults cross-cut and compartmentalise on a scale of <4.7 x 4.7 km (the minimum area required for a doublet system). There may be a possibility of flow perpendicular to slip surfaces in the core of fault zones, but there is much evidence to suggest these fluid pathways will also be cemented.
- Reservoir tortuosity is likely to be increased due to the combined effect of stratigraphic, diagenetic and structural barriers. Low permeability stratigraphy is demonstrated to be laterally discontinuous and as such only limit vertical fluid flow on a very local scale. Diagenesis is unpredictable and very rarely produces laterally continuous barriers over large (km) scales, but will produce local-scale heterogeneity in permeability and porosity. The longer travel time encountered by fluids moving to a potential extraction well may be an advantage within a

geothermal development as it allows fluid time to re-heat back to formation temperature. In the Cheshire Basin, where heat flow is below the UK average (30-50 mW m^{-2} versus 52 mW m^{-2}), the increased transit time may be of benefit.

6.14 References

Adams, C. A., Gluyas, J. G., and Mathias, S. A., 2010, Application of hydrogeological parameters for evaluating the thermal resource potential of deep groundwater systems, BHS Third International Conference : Role of hydrology in managing consequences of a changing global environment.: Newcastle upon Tyne, British Hydrological Society.

Ambrose, K., Hough, E., Smith, N. J. P., and Warrington, G., 2014, Lithostratigraphy of the Sherwood Sandstone Group of England, Wales and south-west Scotland: British Geological Survey Research Report RR/14/01.

Armstrong, J. P., D'Elia, V. A. A., and Löberg, R., 1995, Holywell Shale: a potential source of hydrocarbons in the East Irish Sea: Geological Society, London, Special Publications, v. 93, no. 1, p. 37-38.

Atkins, 2013, Deep Geothermal Review Study Final Report: Department of Energy and Climate Change (DECC).

Beach, A., Lawson Brown, J., Welbon, A. I., McCallum, J. E., Brockbank, P., and Knott, S., 1997, Characteristics of fault zones in sandstones from NW England: application to fault transmissibility: Geological Society, London, Special Publications, v. 124, no. 1, p. 315-324.

Bentley, M. R., and Elliott, A. A., 2008, Modelling Flow along Fault Damage Zones in a Sandstone Reservoir; an Unconventional Modelling Technique Using Conventional Modelling Tools in the Douglas Field, Irish Sea, UK, Europec/EAGE Conference and Exhibition, Society of Petroleum Engineers.

Bertani, R., 2009, Geothermal energy: An overview on resources and potential, International Geothermal Days Conference & Summer School, Volume Vol. 22009: Slovakia.

Bloomfield, J. P., Moreau, M. F., and Newell, A. J., 2006, Characterization of permeability distributions in six lithofacies from the Helsby and Wilmslow sandstone formations of the Cheshire Basin, UK: Geological Society, London, Special Publications, v. 263, no. 1, p. 83-101.

Bonté, D., van Wees, J.-D., and Verweij, J. M., 2012, Subsurface temperature of the onshore Netherlands: New temperature dataset and modelling: Netherlands Journal of Geosciences - Geologie en Mijnbouw, v. 91, no. 4, p. 491-515.

British Geological Survey, 1997, The physical properties of major aquifers in England and Wales, Keyworth, Nottingham, BGS Technical Report WD/97/34 / Environment Agency R&D Publication 8.

-, 2002, Baseline Report Series: 2. The Permo-Triassic Sandstones of west Cheshire and the Wirral: British Geological Survey & The Environment Agency.

-, 2003, Baseline Report Series: 8. The Permo-Triassic Sandstones of Manchester and East Cheshire: British Geological Survey & The Environment Agency.

Busby, J., 2010, Geothermal Prospects in the United Kingdom, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.

-, 2011, UK data for geothermal resource assessments: http://egec.info/wp-content/uploads/2011/09/UK-deep-geothermal-resources_JBusby.pdf, British Geological Survey.

Busby, J., 2014, Geothermal energy in sedimentary basins in the UK: Hydrogeology Journal, v. 22, no. 1, p. 129-141.

Busby, J., Kingdon, A., and Williams, J., 2011, The measured shallow temperature field in Britain: Quarterly Journal of Engineering Geology and Hydrogeology, v. 44, no. 3, p. 373-387.

Chadwick, R. A., 1997, Fault analysis of the Cheshire Basin, NW England: Geological Society, London, Special Publications, v. 124, no. 1, p. 297-313.

Chadwick, R. A., Holliday, D. W., Holloway, S., and Hulbert, A. G., 1995, The structure and evolution of the Northumberland-Solway Basin and adjacent areas: Subsurface Memoir, London: HMSO.

Colter, V. S., 1978, Exploration for gas in the Irish Sea: Geologie En Mijnbouw, v. 57, no. 4, p. 503-516.

-, 1997, The East Irish Sea Basin — from caterpillar to butterfly, a thirty-year metamorphosis: Geological Society, London, Special Publications, v. 124, no. 1, p. 1-9.

Colter, V. S., and Ebbern, J., 1978, The petrography and reservoir properties of some Triassic sandstones of the Northern Irish Sea Basin: Journal of the Geological Society, v. 135, no. 1, p. 57-62.

Cowan, G., 1993, Identification and significance of aeolian deposits within the dominantly fluvial Sherwood Sandstone Group of the East Irish Sea Basin UK: Geological Society, London, Special Publications, v. 73, no. 1, p. 231-245.

Cowan, G., and Bradney, J., 1997, Regional diagenetic controls on reservoir properties in the Millom accumulation: implications for field development: Geological Society, London, Special Publications, v. 124, no. 1, p. 373-386.

DECC, 2013a, Energy Consumption in the UK (2013).

-, 2013b, Oil & Gas: Field Data https://www.gov.uk/oil-and-gas-uk-field-data#uk-production-data.

-, 2016, Oil and Gas: Field Data, https://www.gov.uk/guidance/oil-and-gas-uk-field-data.

Deming, D., 1989, Application of bottom-hole temperature corrections in geothermal studies: Geothermics, v. 18, no. 5–6, p. 775-786.

Downing, R. A., and Gray, D. A., 1986, Geothermal Energy: The potential in the United Kingdom London, HMSO.

Edwards, H. E., Becker, A. D., and Howell, J. A., 1993, Compartmentalization of an aeolian sandstone by structural heterogeneities: Permo-Triassic Hopeman Sandstone, Moray Firth, Scotland: Geological Society, London, Special Publications, v. 73, no. 1, p. 339-365.

Edwards, H. E., and Williams, G. D., 1993, Reservoir Characterisation of the Sherwood Sandstone Group of Liverpool Bay/Morecambe Bay and Adjacent Onshore Areas: Keele University / Hamilton Oil Company.

Evans, D. J., Rees, J. G., and Holloway, S., 1993, The Permian to Jurassic stratigraphy and structural evolution of the central Cheshire Basin: Journal of the Geological Society, v. 150, no. 5, p. 857-870.

Floodpage, J., Newman, P., and White, J., 2001, Hydrocarbon prospectivity in the Irish Sea area: insights from recent exploration of the Central Irish Sea, Peel and Solway basins: Geological Society, London, Special Publications, v. 188, no. 1, p. 107-134.

Gluyas, J. G., and Hichens, H. M., 2003, United Kingdom Oil and Gas Fields Commemorative Millennium Volume: Geological Society, London, Memoirs, v. 20.

Gluyas, J. G., Robinson, A. G., Emery, D., Grant, S. M., and Oxtoby, N. H., 1993, The link between petroleum emplacement and sandstone cementation: Geological Society, London, Petroleum Geology Conference series, v. 4, p. 1395-1402.

Gluyas, J. G., and Swarbrick, R., 2004, Petroleum Geoscience, Blackwell Publishing.

Green, P. F., Duddy, I. R., and Bray, R. J., 1997, Variation in thermal history styles around the Irish Sea and adjacent areas: implications for hydrocarbon occurrence and tectonic evolution: Geological Society, London, Special Publications, v. 124, no. 1, p. 73-93.

Greenwood, P. J., and Habesch, S. M., 1997, Diagenesis of the Sherwood Sandstone Group in the southern East Irish Sea Basin (Blocks 110/13, 110/14 and 110/15): constraints from preliminary isotopic and fluid inclusion studies: Geological Society, London, Special Publications, v. 124, no. 1, p. 353-371.

Griffiths, J., Faulkner, D. R., Edwards, A. P., and Worden, R. H., 2016, Deformation band development as a function of intrinsic host-rock properties in Triassic Sherwood Sandstone: Geological Society, London, Special Publications, v. 435.

Haig, D. B., Pickering, S. C., and Probert, R., 1997, The Lennox oil and gas Field: Geological Society, London, Special Publications, v. 124, no. 1, p. 417-436.

Hardman, M., Buchanan, J., Herrington, P., and Carr, A., 1993, Geochemical modelling of the East Irish Sea Basin: its influence on predicting hydrocarbon type and quality: Geological Society, London, Petroleum Geology Conference series, v. 4, p. 809-821.

Hirst, C. M., and Gluyas, J. G., 2015, The Geothermal Potential Held within Carboniferous Sediments of the East Midlands: A New Estimation Based on Oilfield Data, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Hirst, C. M., Gluyas, J. G., Adams, C. A., Mathias, S. A., Bains, S., and Styles, P., 2015a, UK Low Enthalpy Geothermal Resources: the Cheshire Basin, Proceedings World Geothermal Congress, Melbourne, Australia, 19-25 April 2015.

Hirst, C. M., Gluyas, J. G., and Mathias, S. A., 2015b, The late field life of the East Midlands Petroleum Province; a new geothermal prospect?: Quarterly Journal of Engineering Geology and Hydrogeology, v. 48, no. 2, p. 104-114.

Hitchmough, A. M., Riley, M. S., Herbert, A. W., and Tellam, J. H., 2007, Estimating the hydraulic properties of the fracture network in a sandstone aquifer: Journal of Contaminant Hydrology, v. 93, no. 1–4, p. 38-57.

Holford, S. P., Turner, J. P., and Green, P. F., 2005, Reconstructing the Mesozoic–Cenozoic exhumation history of the Irish Sea basin system using apatite fission track analysis and vitrinite reflectance data: Geological Society, London, Petroleum Geology Conference series, v. 6, p. 1095-1107.

IPCC, 2014, Climate Change 2014 - Mitigation of Climate Change.: Working Group III contribution to the fifth assessment report of the Intergovernmental Panel on Climate Change.

Jackson, D. I., Johnson, H., and Smith, N. J. P., 1997, Stratigraphical relationships and a revised lithostratigraphical nomenclature for the Carboniferous, Permian and Triassic rocks of the offshore East Irish Sea Basin: Geological Society, London, Special Publications, v. 124, no. 1, p. 11-32.

Jackson, D. I., and Mulholland, P., 1993, Tectonic and stratigraphic aspects of the East Irish Sea Basin and adjacent areas: contrasts in their post-Carboniferous structural styles: Geological Society, London, Petroleum Geology Conference series, v. 4, p. 791-808.

Knott, S. D., 1994, Fault zone thickness versus displacement in the Permo-Triassic sandstones of NW England: Journal of the Geological Society, v. 151, no. 1, p. 17-25.

Meadows, N. S., and Beach, A., 1993, Controls on reservoir quality in the Triassic Sherwood Sandstone of the Irish Sea: Geological Society, London, Petroleum Geology Conference series, v. 4, p. 823-833.

Mikkelsen, P. W., and Floodpage, J. B., 1997, The hydrocarbon potential of the Cheshire Basin: Geological Society, London, Special Publications, v. 124, no. 1, p. 161-183.

Naylor, H., Turner, P., Vaughan, D. J., Boyce, A. J., and Fallick, A. E., 1989, Genetic studies of red bed mineralization in the Triassic of the Cheshire Basin, northwest England: Journal of the Geological Society, v. 146, no. 4, p. 685-699.

Newport, L. P., 2016, Petrographic and Geochemical Analysis of the Carboniferous (Namurian) Holywell Shale of northeast Wales [Doctor of Philosophy: Durham University.

Nichols, G., 2009, Sedimentology and Stratigraphy, John Wiley & Sons.

Pasquali, R., O'Neill, N., Reay, D., and Waugh, T., 2010, The Geothermal Potential of Northern Ireland, Proceedings of the World Geothermal Congress, Bali, Indonesia, 25-30 April 2010.

Plant, J. A., Jones, D. G., and Haslam, H. W., 1999, The Cheshire Basin - Basin evolution, fluid movement & mineral resources in a Permo-Triassic rift setting, Nottingham, UK: British Geological Society

Richardson, S. W., and Oxburgh, E. R., 1978, Heat flow, radiogenic heat production and crustal temperatures in England and Wales: Journal of the Geological Society, v. 135, no. 3, p. 323-337.

Rollin, K. E., Kirby, G. A., Rowley, W. J., and Buckley, D. K., 1995, Atlas of Geothermal Resources in Europe: UK Revision: British Geological Survey, Regional Geophysics Series, Technical Report WK/95/07.

Rowe, J., and Burley, S. D., 1997, Faulting and porosity modification in the Sherwood Sandstone at Alderley Edge, northeastern Cheshire: an exhumed example of fault-related diagenesis: Geological Society, London, Special Publications, v. 124, no. 1, p. 325-352.

Seymour, K. J., Ingram, J. A., and Gebbett, S. J., 2006, Structural controls on groundwater flow in the Permo-Triassic sandstones of NW England: Geological Society, London, Special Publications, v. 263, no. 1, p. 169-185.

Smith, I. F., 1986, Mesozoic Basins, *in* Downing, R. A., and Gray, D. A., eds., Geothermal Energy: The Potential in the United Kingdom, HMSO, p. 42.

Tellam, J. H., and Barker, R. D., 2006, Towards prediction of saturated-zone pollutant movement in groundwaters in fractured permeable-matrix aquifers: the case of the UK Permo-Triassic sandstones: Geological Society, London, Special Publications, v. 263, no. 1, p. 1-48.

The Centre for Sustainable Energy, 2012, National Heat Map, Department of Energy and Climate Change (DECC).

TOTAL E&P UK, 2007, A regional review of the Dinantian carbonate play: Southern North Sea and onshore UK: UK DBERR.

Waters, C. N., and Davies, S. J., 2006, Carboniferous: extensional basins, advancing deltas and coal swamps., *in* Brenchley, P. J., and Rawson, P. F., eds., The geology of England and Wales: London, Geological Society of London, p. 173-223.

Wilson, A. A., 1990, The Mercia Mudstone Group (Trias) of the East Irish Sea Basin: Proceedings of the Yorkshire Geological and Polytechnic Society, v. 48, no. 1, p. 1-22.

-, 1993, The Mercia Mudstone Group (Trias) of the Cheshire Basin: Proceedings of the Yorkshire Geological and Polytechnic Society, v. 49, no. 3, p. 171-188.

Yaliz, A., and Chapman, T., 2003, The Lennox Oil and Gas Field, Block 110/15, East Irish Sea: Geological Society, London, Memoirs, v. 20, no. 1, p. 87-96.

Yaliz, A., and McKim, N., 2003, The Douglas Oil Fields, Block 110/13b, East Irish Sea: Geological Society, London, Memoirs, v. 20, no. 1, p. 61-75.

Yaliz, A., and Taylor, P., 2003, The Hamilton and Hamilton North Gas Fields, Block 110/13a, East Irish Sea: Geological Society, London, Memoirs, v. 20, no. 1, p. 77-86.

Chapter 7:

General Discussion & Conclusions*

*Specific discussion and conclusions can be found in individual Chapters 3-6.

7.1 Summary of Thesis Objectives

The original remit of the thesis was to re-assess the UK low-enthalpy geothermal resource base, the reason being the advancement in technologies and access to more deep well data from the hydrocarbon industry. In addition the UK has a commitment to reduce CO_2 levels and increase renewable resource uptake (Directive 2009/28/EC, 2009; IPCC, 2011). Assessing the UK geothermal resource base is something that was first undertaken in the 1980's (Downing and Gray, 1986), with a re-assessment in 1995 (Rollin et al., 1995). The resource assessment relies upon deep (>500 m) well data, but these data are not always easy to obtain. In the case of the original UK resource assessment a mixture of data from specifically drilled geothermal wells, water wells, boreholes and some hydrocarbon wells were used. The most promising low-enthalpy geothermal locations were identified as Mesozoic (Permo-Triassic) deep sedimentary basins that have subsequently been quantified. These calculated values are still widely quoted today. Geothermal resource quantification in sedimentary basins relies on being able to produce a reasonable estimate of aquifer properties (porosity, permeability, thickness, transmissivity) and temperature at depths >2 km. Assignment of a resource value becomes a high risk proposition if supporting deep well data are lacking. Since 1995 only two geothermal projects have resulted in wells being drilled; Eastgate, Co Durham and Science Central, Newcastle-Upon-Tyne. Both these projects departed from assessing Permo-Triassic basins and signalled a step away from re-assessment and a move towards new assessment of unquantified resources, particularly those associated with Carboniferous sediments (Science Central) and a Devonian granite (Eastgate). These developments, along with new access to formerly commercially sensitive, large datasets from onshore and offshore oil fields, has defined the direction this project has taken.

New geothermal resources associated with previously unquantified Carboniferous strata in the East Midlands formed the initial focus of this thesis. The overlying Permo-Triassic basin has previously been quantified but the underlying oil-bearing Carboniferous sediments had not; co-produced water in these fields was identified as a potential source of heat that could add not only to the overall UK geothermal resource base, but also extend the lifespan of these oilfields. The significance of such work not only adds further to the geothermal resource base with a unique resource, but has also challenged the convention that these areas do not form a viable geothermal resource. Established hydrocarbon fields are often well understood systems and have a lot of data associated with them. Re-purposing these data for geothermal use is a cheap way of de-risking geothermal development. In addition, a geothermal development could use much of the existing petroleum infrastructure thus reducing both capital costs and operational costs. Indeed, simops, that is simultaneous exploitation of the petroleum and geothermal resource, is possible and in many instances may be highly desirable as hot water is naturally produced with the oil. The wider implication of this work is thus that the resource can be accessed without the costs and risk of a traditional deep geothermal development. The overall extractable heat resource value for 23 assessed oilfields within the East Midlands was estimated at 2.6 MW_t. Further targeted assessment of the Welton field indicated inclusion of additional water-bearing strata could almost double the available extractable heat within this field (0.91 MW_t increased to 1.6 MW_t). End-users for the heat were identified; agricultural (greenhouse) use was deemed the most effective.

Use of offshore oil and gas field data from the East Irish Sea Basin has been used to better constrain aquifer property values for the onshore Cheshire Basin. The two basins are linked and their burial and thermal histories are comparable. The implications for the Cheshire Basin from this work is that the original resource assessments are confirmed but importantly access to those resources will be more difficult than has hitherto been realised. This is because the reservoir quality is likely to be poorer in the deeper Permian strata than was assumed by the work in the 1980s. If is the case, well stimulation may be required to extract fluid from the deepest parts of the basin at sufficient rates for a geothermal development. In addition, compartmentalisation is likely in some areas of the basin. Other identified flow barriers (sedimentological, diagenetic and structural) are shown to be beneficial rather than limiting and adds further knowledge to methods of exploitation of the Cheshire Basin resource. The wider implication of this work is twofold. Firstly the use of offshore oilfield analogues can better quantify onshore equivalents where data is limited. Secondly, the assessment has furthered the understanding of likely connectivity of target reservoirs, and the scale over which they extend, thus informing future geothermal exploration.

7.2 General Discussion

The work within this thesis has added further value to the geothermal resource base of the UK. This "added value" can be quantified as per the estimation of extractable heat available in previously unquantified Carboniferous strata underlying the East Midlands and identification of the end users of such heat. It also adds value in as much as the previously identified and quantified resource of the Cheshire Basin may not be as accessible as previously thought, and stimulation of this basin is likely for deeper (Permian) sandstone geothermal targets. The primary hypothesis is ultimately proven. However, having a large resource base does not equate to an increased level of uptake, nor does having locations that have the ability to perform as well as or better than the only proven UK resource (Southampton). The wider implication of the work only becomes important if it leads to further development of geothermal resources in the UK. Barriers to geothermal development have been discussed at length in Chapter 3 and are re-iterated to an extent here.

Previous resource assessments have focused primarily on generating power. Power generation is difficult (if not impossible) to achieve efficiently with low enthalpy geothermal resources, even with the use of improved Organic Rankine Cycle technology. This restricts power generation to areas where temperatures exceed 100°C (more likely 150°C). These resources are, therefore, restricted to a handful of localities. The resource is confined to deeper subsurface areas that are correspondingly less well understood and thus much higher risk developments; attracting investment is difficult. Data presented by DECC (2015) indicate almost 50% of the energy we consume is used for heating purposes. On a domestic level this equates to consumption of two thirds of the total UK gas supply (Younger et al., 2015). The above information suggests it would be pertinent to invest in heat-only geothermal schemes. The outlook of the UK geothermal industry appears to back geothermal heat as the viable option also, which is at odds with current and previous Government reports; their most recent report by Atkins (2013) focuses on power despite several academic and industry figures suggesting heat should form the initial focus. Answers to a questionnaire by industry, academic and Local Authority representatives within the Atkins (2013) report (found in Appendix C.2 of this report) indicate heat-only geothermal projects should be economically viable before power generation is considered.

As depicted by Figure 3-21, geothermal is still in the "Research" phase, meaning any geothermal resource development is likely to be on a relatively small scale with a primarily academic influence to prove the concept works. It is also likely to be small due to the difficulty in funding such ventures; funding needs to come largely from institutional investment i.e. Local Authority / Government / EU funded. The low temperatures involved in UK low enthalpy resource assessment do not make it an attractive proposition for investment by industry; aside from the risks involved, a barrel of hot water does not hold the same value (with regards energy value or monetary value) as a barrel of oil and payback differs as a result.

With the inclusion of new geothermal resource estimates from previously untested strata, the case for developing geothermal heat grows. Without appropriate backing, however, the developed resource base will remain untouched. Further to this, an appropriate geothermal governing body is considered necessary (if not essential) if geothermal in the UK is to move forward. Deep geothermal falls under the wing of the Renewable Energy Association (REA) rather than having a standalone UK geothermal association. BritGeothermal, established in 2013, involves Durham University, Newcastle University, the University of Glasgow and the British Geological Survey, with the aim to collaborate and promote deep geothermal energy research. Some development has been achieved through BritGeothermal, but wider collaboration is required ideally between academic institutions (currently Durham University, University of Glasgow, Newcastle University, Keele University, Cambridge University, BGS) and industry partners (Geothermal Engineering Ltd, EGS Energy, Cluff Geothermal Ltd). Data are being treated as commercially sensitive and thus not shared with an industry that is not yet fully established; whilst individuals work on geothermal, the wider impact of the technology is lost. Projects will remain small-scale as a result. Sharing risk amongst all these institutions could allow the further development of geothermal resources in the UK. If multiple institutions collaborated and financially backed each other, an effective risk insurance scheme could be operated and perhaps then, and only then, could the next geothermal borehole begin to be drilled.

7.3 Wider Implications of Thesis Findings

To place the findings of this thesis into further context, and to better summarise the findings of this thesis, the total extractable heat equation presented in Chapter 4 has been used to produce Figure 7-1, which effectively summarises likely extractable heat based on flow rate and temperature differential. Fixed values of specific heat capacity (3.93 kJ kg^{-1} K), density (1.045 Mg m^{-3}) and temperature differential (ΔT, °C) based on saline water can be used in conjunction with variable flow rate (m^3 d^{-1}) to obtain several fixed extractable heat curves. Superimposed on Figure 7-1 are known flow rates from wells within the East Midlands, Cheshire, the Douglas and Lennox Fields (East Irish Sea Basin) and Southampton. Highlighted in green is considered the most likely temperature differential available (i.e. for a ΔT of 40°C, the minimum resource temperature would realistically be 60°C, with a reinjection temperature of 20°C). The plot gives an idea of the total extractable heat available if flow rate and temperature can be reasonably estimated. It is not an absolute measure, but gives a reasonable estimate. The graph indicates both the East Midlands and Cheshire Basin could match (and potentially exceed) the resource being exploited at Southampton.

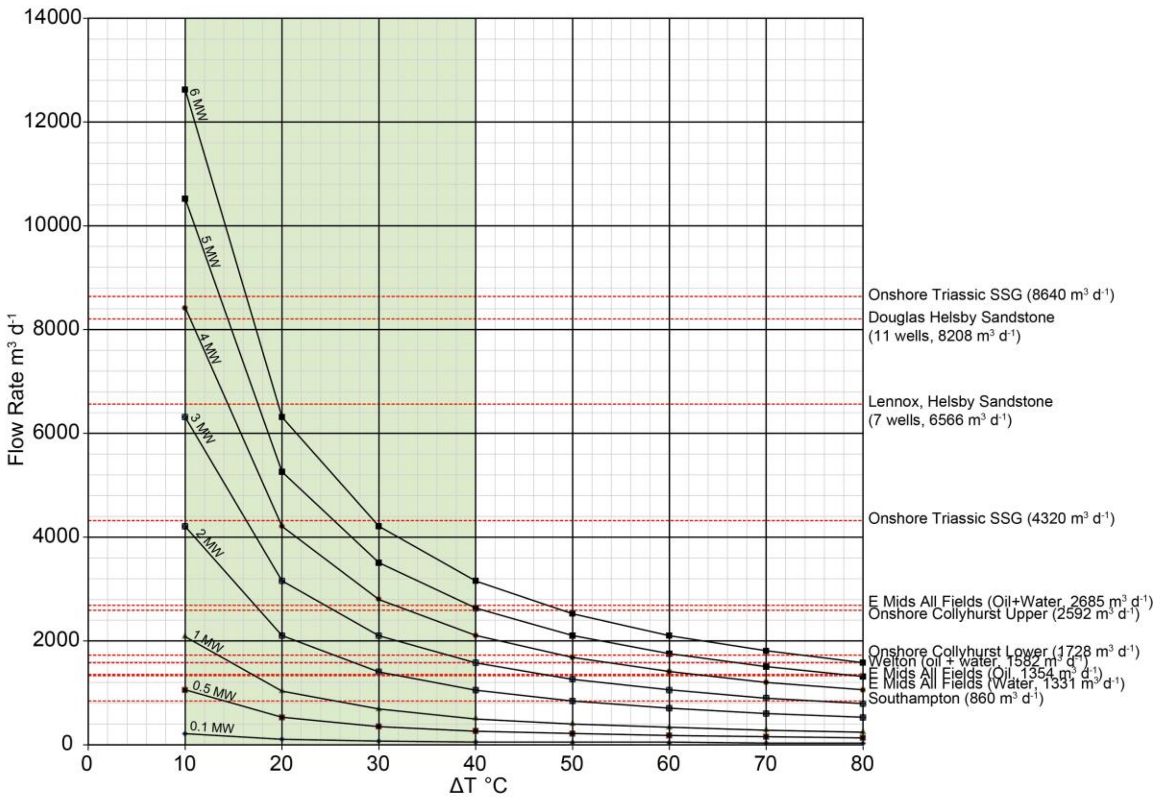


Figure 7-1: Total extractable heat determined from fixed values of specific heat capacity, density and temperature differential and variable flow rate. A quick assessment of potential extractable heat can be made if flow rate and resource temperature are known or can be reasonably estimated.

Figure 7-1 is also useful when assessing whether low temperature differential-high flow rate systems should be chosen as development targets over high temperature differential-low flow rate systems as either of these end-members can produce the same extractable heat value. High flow rate and low temperature differentials (ΔT = 10-20°C) are typically associated with shallower (750-1500 m) low-enthalpy resources where formation temperatures are <40°C, but flow rates are better understood. Low flow rates and high temperature differential (ΔT = 20°C+) equates to deeper resources (1500 m+) where the resource may be hotter (60-100°C), but the amount of available fluid is more difficult to constrain. Choosing which end member is more viable to exploit is difficult as each has its pros and cons, and is essentially something that will form potential future work (discussed within Section 7.4.3).

Data evaluation and re-evaluation to give confidence that geothermal can be viable has reached the stage where new geothermal wells are required. Evaluation of existing data can only take the technology so far and now practical lessons need to be learned; new data are important and are required to further our understanding of UK geothermal resources. Technological capabilities have moved forward since the original installation of the Southampton borehole. It is my opinion that new wells are the only way to kick start the geothermal industry. The work presented here provides novel ways of de-risking the drilling process. It has also been suggested collaborative efforts between the shale gas and hydrocarbon industry might offer further risk management benefits (dual purpose wells can be installed whereby both gas and hot water can be extracted at differing stratigraphic levels). Well head design can and have been modified to take both energy streams if required. This synergy between extractive industries is another way in which geothermal can be made viable.

7.4 Principal Conclusions

It should be noted that Chapter-specific conclusions are contained within Chapter 3, 4, 5 and 6. Here a more general summary is provided.

- The overall value of the UK geothermal resource base has increased based on new estimates of geothermal resource contained within Carboniferous sediments of the East Midlands, and the Permo-Triassic strata of the Cheshire Basin. These are comparable, if not in excess, of the proven resource exploited at Southampton.
- Data-rich offshore analogues can be used to better constrain aquifer properties for data-poor onshore targets. In addition offshore analogues can be used to determine the likelihood of connected aquifer which goes beyond just quantifying the resource. Potential factors that could limit the resource can be identified earlier and be addressed.
- The risk involved with developing a geothermal resource is high, but can be reduced if the geothermal industry can create partnerships with existing holders of large volumes of deep well data i.e. the hydrocarbon industry. Access to these hydrocarbon data will allow quicker assessment of potential target aquifers without necessarily having to drill further exploration wells.
- Making use of industries that already produce / create hot water, such as the oil industry, provides a relatively cheap way to promote geothermal on a local scale and could create a new heat market. The infrastructure is already in place to develop the resource, again reducing the cost of developing the resource.
- Increasing the value of the UK geothermal resource base will not increase the uptake of geothermal resources. It is important for new areas to be quantified to truly reflect the potential geothermal technology has to offset CO_2 emissions and contribute to satiating UK heat demand. However, quantifying the resource base alone will not promote the uptake of this technology over any other renewable technology.
- The low temperatures involved in UK low enthalpy resource assessment do not make it an attractive proposition for investment. A barrel of hot water does not hold the same value (with regards energy value or monetary value) as a barrel of oil. However, geothermal developments are not high polluting industries, with only low levels of emissions (<1 g CO_2 per kWh_t) associated with direct-use geothermal systems. Geothermal attracts minimal emission-based taxes when compared to

other technologies. This brings balance to the argument geothermal is not as valuable as a conventional energy source.

7.5 Next steps

To specifically build upon the work undertaken in this thesis further work has been identified.

7.5.1 The East Midlands

- Identification of other water-bearing intervals within individual fields is required to determine the total available fluid that may be available for extraction; currently the extractable heat calculated in Chapter 5 is based on published flow rates only. From these data a more targeted resource calculation can be undertaken following the same methodology outlined in Chapter 4. This will provide a better estimate of the available resource in the East Midlands oilfields.
- A GIS-based assessment of the land-use surrounding gathering centres / well heads will determine the best use of any co-produced fluid (agricultural, industrial or district heating). The economic case can be stated for these areas for the most suitable use of the extractable heat.
- Carrying out an analysis of facies across oilfields and areas outwith the fields to estimate the potential for intervening areas to contain water-bearing horizons. Extrapolating flowing horizons to the areas between fields will increase the volume of rock available to extract fluid (and heat).

7.5.2 The Cheshire Basin

- Update the model for the Cheshire Basin adding in fault barriers, define a flow tortuosity parameter, and include new estimated porosity and permeability data for deep (Permian) sandstones. This assessment will allow a more realistic computation of resource.
- Compare and contrast the economic benefits of developing lower temperature (20-40°C) resources with correspondingly high flow rates in shallower areas of the basin, versus higher temperature (40°+) resources at lower flow rates in deeper areas of the basin. The shallower sandstone aquifers of the basin are better understood and have excellent reservoir properties, but will be <40°C. It is proposed work is undertaken to assess the economic argument each case.
- A reassessment of data associated with the only two wells to fully penetrate the Cheshire Basin Permo-Triassic fill (Knutsford-1 and Prees-1) is considered pertinent to better constrain the deep porosity.

7.5.3 General future work

Through the use of Figure 7-1 it is suggested further work is undertaken in relation to this concept to determine the type of geothermal system that may be more viable at this stage in geothermal development. As presented in the discussion above the figure can be used as a step into further economic and risk-based study into development of low-enthalpy geothermal resources; are low temperature (20-40°C)-high flow rate systems more viable than high temperature (60-100°C)-low flow rate systems? Furthering our understanding of the pros and cons of such systems may allow this question to be answered and further promote the most viable style of low-enthalpy geothermal resource.

7.6 References

Atkins, 2013, Deep Geothermal Review Study Final Report: Department of Energy and Climate Change (DECC).

DECC, 2015, Energy Consumption in the UK (2015): Overall energy consumption in the UK since 1970.

Directive 2009/28/EC, 2009, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

Downing, R. A., and Gray, D. A., 1986, Geothermal Energy: The potential in the United Kingdom London, HMSO.

IPCC, 2011, Special Report on Renewable Energy Sources and Climate Change Mitigation, United Kingdom and New York, NY, USA, Cambridge University Press.

Rollin, K. E., Kirby, G. A., Rowley, W. J., and Buckley, D. K., 1995, Atlas of Geothermal Resources in Europe: UK Revision: British Geological Survey, Regional Geophysics Series, Technical Report WK/95/07.

Younger, P. L., Feliks, M. E. J., Westaway, R., McCay, A. T., Harley, T. L., Elliott, T., Stove, G. D. C., Ellis, J., Watston, S., and Waring, A. J., 2015, Renewing the Exploration Approach for Mid-Enthalpy Geothermal Systems: Examples from Northern England and Scotland, Proceedings of the World Geothermal Congress, Melbourne, Australia, 19-25 April, 2015.

Appendix A:

The Late Field Life of the East Midlands Petroleum Province – A New Geothermal Prospect?

‘As published’ paper after Hirst et al. (2015b)

Appendix B:

The Geothermal Potential held within Carboniferous Sediments of the East Midlands: A New Estimation based on Oilfield Data

‘As published’ paper within the World Geothermal Congress Conference Journal (2015)

Appendix C:

UK Low Enthalpy Geothermal Resources: The Cheshire Basin

‘As published’ paper within the World Geothermal Congress Conference Journal (2015)

Appendix D:

Data pertaining to Chapter 4 – The Welton Field

D.1: Well locations, calculated temperature gradients

D.2: Extractable heat calculation

D.3: Porosity& Permeability data, kv/kh calculation

Appendix E:

Data pertaining to Chapter 5 – The East Midlands

E.1: Production rate data, all fields

E.2: Temperature correction

E.3: Extractable heat calculation (all fields)

Appendix F:

Data pertaining to Chapter 6 – The Cheshire Basin

F.1: All onshore borehole and water well locations.

F.2: All onshore borehole/water wells >500 m depth.

F.3: Summary of all offshore well temperatures.

F.4: Onshore and offshore porosity and permeability data.

F.5: Offshore cumulative permeability:depth data.

F.6: Summary of major onshore fault throws and widths.